Technical Appendix A: Global Assumptions

Contents

Introduction 1
Analysis Period 2
Economic and Financial Assumptions 2
Dollar Year and Adjustment Factors 2
Discount Rate 2
Financing Assumptions 3
Approach to Consistent Treatment of New Resource Costs 7
Approach to Social Cost of Carbon 9
Transmission and Distribution Considerations for Resources 10
Line Loss Assumptions for Demand-Side Resources 11
Transmission and Distribution Deferral Values 11
Modeling Zones 12

Introduction

Early in the power planning process, the Council defines a set of assumptions that are used across different elements of the analysis. This technical appendix provides details around many of the global assumptions used in the Ninth Power Plan modeling.

In addition to the information presented in this appendix, the following technical appendices also detail assumptions that are used across many elements of the analysis:

- Technical Appendix B – Existing System Parameters and Policies
- Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits
- Technical Appendix D – Climate Model Data and Assumptions

Analysis Period

Under the Northwest Power Act, the Council's Power Plan is to put forth a scheme for new resources, including demand-side resources such as conservation, to reduce or meet the Bonneville Power Administration's obligation.[1] In addition, the Council is to include "a demand forecast of at least twenty years."[2] This has resulted in the Council typically analyzing a 20-year period for power planning, as the long-term demand forecast is useful for informing near-term resource decisions.

At the start of every power plan process, the Council decides on the 20-year analytical period to align all data and modeling assumptions. Given the prevalence of hydropower in the region, much of the Council's modeling is done in terms of a "water year," which is defined as the period of October 1 through September 30. For the Ninth Power Plan, the 20-year period is represented by October 2026 through September 2046. Translating this into calendar terms, this essentially represents 2027-2046.

While the Council analyzes 20 years into the future, the focus of recommendations is for the near-term action plan period. This is defined as the first six years of the power planning horizon: October 2026 through September 2032 (or 2027-2032).

Economic and Financial Assumptions

The Council's power planning process involves several analytical steps including projecting future demand for electricity, estimating the quantities and costs of new resources, and simulating operations of the power system to meet future needs with those new resources. Each of these steps requires assumptions around financial and economic variables. It is critical to align these assumptions to ensure that comparisons are made on an apples-to-apples basis. This section details the assumptions the Council used in the Ninth Power Plan to align financial assumptions.

Dollar Year and Adjustment Factors

The Ninth Power Plan assumes a base dollar year of 2024 for all financial assumptions. This ensures consistency in the treatment of cost assumptions throughout the analysis. The Council uses consumer price index (CPI) deflators data assumptions from S&P Global Market Intelligence to consistently adjust to 2024 dollars across planning assumptions.

Discount Rate

As the power plan analysis covers a 20-year horizon, the Council uses a discount rate to account for the time preference of money. To understand the concept of time preference, consider the general observation that people, given the choice, would prefer to consume now rather than later. This time

[1] Northwest Power Act, §4(e)(2), 94 Stat. 2706.
[2] Northwest Power Act, §4(e)(3)(D), 97 Stat. 2706.

preference is also related to market interest rates. Essentially, the idea is that a dollar paid next year is less of a burden than a dollar today because that dollar could be invested and, assuming a sufficient rate of return, the proceeds from that return could be used to pay the dollar cost in the future year. Using a discount rate allows the Council to translate costs incurred at different times into comparable present values, enabling a fairer comparison of the new resource options considered in the plan.

To take an example, there are some resources that have high upfront costs with low variable or operating costs. This could include resource options like solar, wind, and conservation. The costs are predominantly incurred at the beginning of resource development, with little to no ongoing maintenance costs. On the other hand, there are resource options that have costs that incur both at the beginning, as well as ongoing variable and fixed costs from maintenance and fuel. An example would be a natural gas turbine. These two cost streams would vary depending on the time preference. If costs today were valued the same as costs in the future (i.e. a 0% discount rate), a resource that has higher upfront costs, but lower long-term costs would look relatively cheaper than the alternative. Alternatively, a higher discount rate reduces the importance of future costs compared to today, causing those resources with higher ongoing costs to look relatively cheaper.

For the Ninth Power Plan, the Council used Northwest utility discount rates and created a blended approach based on a sales-weighted average for those utilities. This included data from all the investor-owned utilities in the region, Bonneville Power Administration, and Tacoma Power.[3] This resulted in a discount rate of 3.7%.[4]

Staff conducted a sensitivity on the discount rate using Aurora, the Council's West-wide capital expansion model. For this sensitivity, staff used both the sales-weighted 3.7% discount rate and the Bonneville Power Administration's 2.8% discount rate in a West-wide market study. The result showed negligible difference in Northwest builds, suggesting that a 1% difference in discount rate is not going to drive significantly different resource decisions in the region (rather, other factors are likely driving those resource decisions).

Financing Assumptions

Determining the present value cost of any resource requires additional considerations around who pays for the resource. These assumptions vary by resource.

Demand-Side Resources

For demand response, the only financing assumption used to determine present value costs is the discount rate, as described earlier.

[3] The Council also received data from Grant PUD and Clark PUD, both of which assumed the Council's discount rate from the 2021 Power Plan. Since these were developed from prior Council work (using a similar methodology), staff decided to exclude these from the sales-weighted approach.

[4] This workbook outlines the discount rate analysis: https://nwcouncil.box.com/v/ninthplandiscountrate.

For conservation and rooftop solar, the underlying assumptions of sponsor costs rely on the same data set as used to create the discount rate, namely utility data. For these resources, the Council also includes assumptions regarding who pays for the cost (e.g. customer vs utility) and the portion of the cost paid for by each entity (e.g. initial capital cost, administrative cost, maintenance costs, etc.). For the consumer portion of the sponsor costs, the Council used information from the Federal Reserve's Survey of Consumer Finances data.[5]

One notable change for the Ninth Plan is the assumption around who pays for the upfront capital cost of the measure. In previous power plans, the Council assumed that some portion of this cost for conservation was paid for by consumers. The Council changed this approach for the Ninth Plan to assume the utility pays the full cost of conservation, consistent with the treatment of all other resources considered in the analysis. The Ninth Plan continues to assume that consumers pay for the ongoing annual operations and maintenance (O&M) costs associated with the resource.

The financial assumptions used to calculate present value vary by sector, primarily driven by difference in the assumed administrative costs. The tables below provide the final assumptions as used in the Council's ProCost tool, which calculates the levelized cost[6] of conservation and rooftop solar resources.

Table A - 1: Residential Sector Financial Input Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital[7]	4.2%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.16		

[5] These data were captured in a Department of Energy 2022 Technical Support Document for Furnace Fans. The specific data are from Table 8.3.7 in the TSD, available here: https://www.regulations.gov/document/EERE-2021-BT-STD-0029-0014.

[6] The levelized cost of a resource is the present value of the lifetime cost of the resource, allowing for a comparison of resources with different lifetimes and other attributes to be compared on a cost basis.

[7] The real after-tax cost of capital refers to the final cost of an expense after all applicable taxes and tax benefits are accounted for, adjusted for inflation.

Table A - 2: Commercial Sector Financial Input Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	5.2%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.13		

Table A - 3: Industrial Sector Financial Input Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	5.8%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.06		

Table A - 4: Agricultural Sector Financial Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	4.9%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.12		

Table A - 5: Utility System Financial Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	3.8%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.12		

More information on how financial input assumptions are used in demand side resources are available in Technical Appendices H, I, and J, covering conservation, demand response, and rooftop solar, respectively.

Supply-Side Resources

For generating resources, financing assumptions also include assumptions regarding tax rates, insurance, debt, and return on equity. Assumptions related to debt and return on equity are then weighted based on sponsor share, assuming 60% utility and 40% merchant/independent power producer. All financing assumptions, including the debt and equity ratings are informed by the U.S. Environmental Protection Agency's assumptions for power sector modeling.[8] Table A - 6 provides the generating resource financing assumptions assumed in the Ninth Power Plan.

[8] Documentation of financing assumptions for EPA's power sector modeling are available here: https://www.epa.gov/system/files/documents/2021-09/chapter-10-financial-assumptions.pdf.

Table A - 6: Utility Scale Generating Resource Financing Assumptions

Parameters	Ninth Plan Assumption		
Federal income tax rate	21%		
State income tax rate	6.45%		
Property tax	0.9%		
Insurance	0.3%		
	Utility	**Merchant/IPP**	**9P Assumption**
Debt fraction	50/50	55/45	52/48
Debt interest rate (nominal)	3.5%	6.27%	4.61%
Return on equity (nominal)	7.17%	9.74%	8.20%

More information on the financial assumptions of supply-side resources is available in Technical Appendix G – New Generating Resources.

Approach to Consistent Treatment of New Resource Costs

The Power Act directs the Council to develop a power plan that gives priority to resources that are cost-effective.[9] Cost-effective means that such resources or conservation measures are forecast to be reliable and available within the time it is needed. The resources also must "meet or reduce the electric power demand … at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof."[10] Therefore, a resource is only cost-effective in comparison to other measures or resources (or combination of resources), and it is the incremental system cost that provides a basis for comparison between resources.

To support this comparison, the Council works to ensure that all new measures and resources are assessed on even footing. Key to this, is a consistent treatment of costs for new resource options. Early in the power plan process, the Council developed a framework for the consistent treatment of costs, connecting each element back to its underpinning in the Power Act.

Core to the bulk of the cost comparison between resources is the definition of system cost in the Power Act:

[9] Northwest Power Act, §4(e)(1), 97 Stat. 2706
[10] Northwest Power Act, §3(4)(A), 97 Stat. 2706.

> "… an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource."[11]

In addition to system cost, the Council also considers other elements of costs that connect to directives of the Power Act, including a 10% preference adder for conservation[12] and the importance of adequacy and reliability[13].

To account for all these elements together, the Council created a resource cost framework that identifies costs to consider for a measure and how that cost is treated across resources.[14] The Council uses a "total cost" perspective to reflect resource costs, regardless of who pays for those costs. The goal of the framework is to provide consistency (or symmetry) in treatment of costs across all resources. The Council recognizes, however, that consistency is not required under the statute, nor is it always possible or appropriate across resources. Not all direct costs and benefits of a measure or resource are quantifiable, nor are all costs equally applicable as the statute acknowledges may be the case in the definition of system costs. Additionally, especially when considering quantifiable environmental costs and benefits, the Council takes care to not double count the quantified effect as both a cost for one resource and a benefit for another resource.[15]

For the Ninth Power Plan, the Council updated two areas for cost treatment: treatment of state tax credits and valuing resiliency for buildings provided by certain resources. Regarding state tax credits, the Council historically has treated those as in-region transfer payments, essentially ignoring them for the purposes of developing resource costs. For the purposes of the Ninth Power Plan, the Council shifted this approach to recognize that the funding to support state tax credits represents a range of sources outside of ratepayer funds, including federal dollars flowing to the states. Therefore, the Council decided to apply state tax credits as a reduction to the total cost, where applicable.

The Council's 2021 Power Plan identified that some resources, specifically conservation resources, could provide resiliency benefits for buildings. This was highlighted after events like the Texas freeze in 2021 which identified the importance of building resilience when the power is out. Since the 2021 Power Plan, the Council's Regional Technical Forum (RTF) developed a methodology for determining a quantifiable benefit for resiliency of buildings for resources that provide value when the system is

[11] Northwest Power Act, §3(4)(B), 97 Stat. 2706
[12] Northwest Power Act, §3(4)(D), 97 Stat. 2706
[13] Northwest Power Act, §2(2), 97 Stat. 2706
[14] This decisions on cost treatment for the Ninth Power Plan have been captured in the Council's Quantifiable Resource Cost Framework document: https://nwcouncil.box.com/v/ninthplancostframework.
[15] More information on the Council's treatment of quantifiable environmental costs and benefits is available in Technical Appendix C: Methodology for Quantifiable Environmental Costs and Benefits.

down. This work is available on the RTF website.[16] The values are $0.0018/kWh for gas-heated homes, $0.0062 for heat pump heated homes, and $0.0078 for electric resistance heated homes and were applied to weatherization measures for conservation.

More information on cost assumptions for resources is available in Technical Appendices G, H, I, and J, covering new generating resources, conservation, demand response, and rooftop solar, respectively.

Approach to Social Cost of Carbon

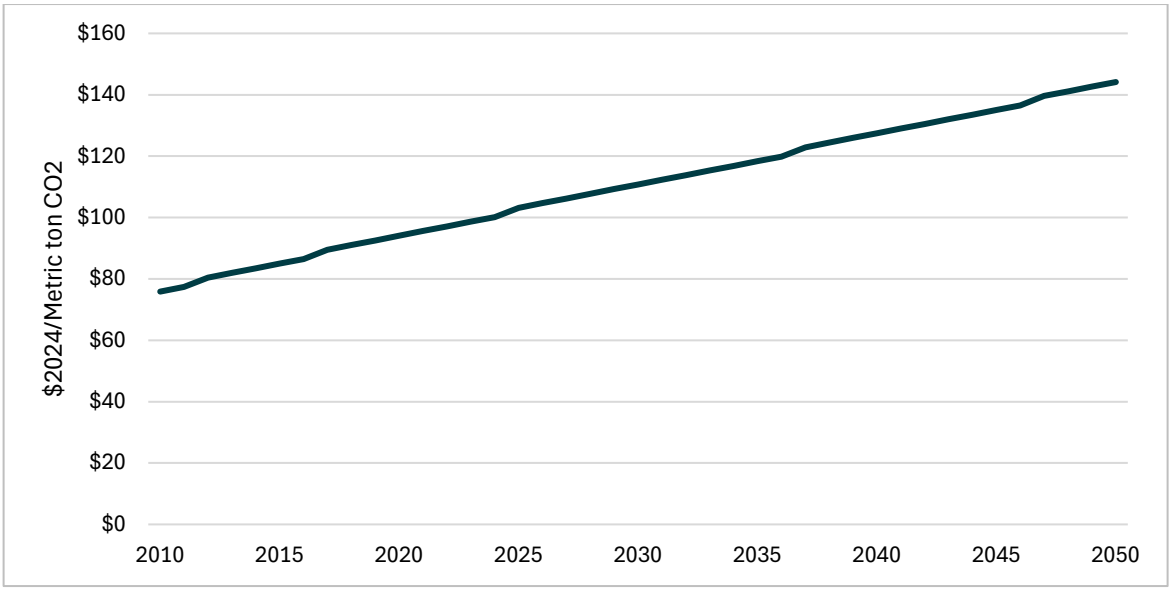
The social cost of carbon (SCC) is an estimate, in dollars, of the global damages from a ton of carbon dioxide. The Council has used the SCC in various ways in its power planning to monetize environmental impacts from carbon and other emissions. For the Ninth Power Plan, the Council is using the SCC where required by specific jurisdictions.

The Council kicked off its official power plan review in February 2025. At this time, the Trump Administration updated federal guidance and requirements to remove the use of the SCC for planning. Given this federal guidance, rather than applying the SCC to resource decisions for the full region, the Council opted for a different approach for the Ninth Power Plan. The Council will apply the SCC only where required by specific jurisdictions. At the time of power plan development, Washington state was the only jurisdiction in the region requiring the use of the SCC in resource decisions.

In May 2019, Washington's Governor Inslee signed into law the Clean Energy Transformation Act (CETA). This legislation places many requirements on utilities, as the state moves towards a greenhouse-gas-emission-free electricity system by 2045. One of these requirements is for electric utilities to "… consider the social cost of greenhouse gas emissions … when developing integrated resource plans and clean energy action plans."[17] CETA goes on further to require electric utilities to use the SCC as a cost-adder when evaluating conservation and developing integrated resource plans. The specific value for the SCC required by CETA is determined by the Interagency Working Group on SCC using a 2.5% discount rate.[18] The specific assumptions for SCC are shown in Figure A - 1.

[16] https://rtf.nwcouncil.org/other/energy-efficiency-resilience-valuation-methodology-study.
[17] Washington CETA, SB 5119, 2019, § 14(3).
[18] Washington CETA, SB 5119, 2019, § 15. This specifically points to Table 2 under the Technical Support Document published under Executive Order No. 12866 on August 16. The Technical Support Document is available here: https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

Figure A - 1: Social Cost of Carbon Values[19]



To implement this approach, the Council ultimately relied on carbon pricing for Washington. In 2021, Washington passed the Climate Commitment Act.[20] This legislation established a cap-and-invest program creating carbon pricing in the state. The Council used these carbon prices as a proxy for planning with a SCC, but just for the state of Washington. While the carbon prices are not equivalent to the SCC values required by CETA, the prices provide a reasonable proxy and the approach aligns well with the capabilities of the Council's modeling suite.[21]

Transmission and Distribution Considerations for Resources

In the Council's modeling suite, loads and resources are compared at a common point of generation busbar. For the Ninth Power Plan, this analysis is done within 17 zones for the region. Within the models, this zonal approach allows for some analysis on the locational value of resources based on transmission development, but it does not provide any insight on the relative value of resources within zones. To allow for apples-to-apples comparison of resources, while also accounting for transmission and distribution considerations not directly modeled, the Council must develop common assumptions around transmission and distribution system characteristics as part of new resource development. This section outlines those assumptions.

[19] More details behind these values is available here: https://nwcouncil.box.com/s/26txw1xs904xr0pw89rbhgcmn8kdjvjv.
[20] More information on the Climate Commitment Act is available on the Washington State Legislatures' website: https://app.leg.wa.gov/billsummary?billnumber=5126&year=2021.
[21] More information on the Council's modeling framework is available in Technical Appendix K: Modeling Framework.

Line Loss Assumptions for Demand-Side Resources

As part of comparing resources to a common point of generation busbar, demand-side resources (conservation, demand response, and rooftop solar) are grossed up to account for line losses that would have occurred had a generating resource produced the power saved. In other words, the Council takes the savings assumed at the site of delivery and adds to it additional savings to represent the line losses from moving energy from generation to load. For the Ninth Power Plan, the Council updated its assumption of line losses for demand-side resources. The Council contracted with GDS Associates who obtained average line loss data from 56 utilities representing 83% of the regional load. These data were then weighted (using system load for transmission loss weighting and utility size information for distribution loss weighting) to determine the final average line loss assumptions for the plan as shown in Table A - 7. More background and details on the approach are provided in the materials presented at the September 24, 2024[22] and November 6, 2024[23] Conservation Resources Advisory Committee meetings.

Table A - 7: Ninth Plan Line Loss Assumptions

Loss	Assumption
Transmission	2.8%
Distribution	4.4%
Total	7.2%

Transmission and Distribution Deferral Values

Certain resources can defer investment in transmission and/or distribution systems. While the Council's modeling will assess the locational value of resources across 17 zones, and therefore the value of deferring large, interzone transmission development, the models will not assess this value within zones. Instead, the Council develops transmission and distribution deferral values to capture this system benefit for the relevant resource options, such as conservation. This value is included in the costs of relevant resources.

For the 2021 Power Plan, the Council updated its approach to estimating transmission and distribution deferral values. After reviewing many of the methodologies across the region, the Council (with input from regional experts) chose to use PacifiCorp's methodology for determining these deferral values. The Council collected data from five utilities and load-weighted the results for a single regional value for use in the power plan.

[22] https://www.nwcouncil.org/calendar/conservation-resources-advisory-committee-2024-09-24.
[23] https://www.nwcouncil.org/calendar/conservation-resources-advisory-committee-2024-11-06.

For the Ninth Power Plan, the Council built on this approach by using a similar survey instrument to collect data from utilities. In addition, the Council collected data from integrated resource plans, conservation potential assessment, and other documents. Because of the zonal modeling approach, staff focused on collecting data that represented the value of transmission deferral within a zone. This resulted in data from 11 regional utilities. Of these utilities, four of them pointed to the Council's assumptions for the 2021 Power Plan. Staff decided to remove these from the analysis, leaving the data from the remaining seven utilities. The data showed significant differences across the region, particularly between utilities on the west side of the Cascades verses those on the east. Since there wasn't sufficient data to develop a value per zone, while also recognizing the difference across the region, the Council developed a "West" value and an "East" value. Additionally, the Council developed a "Regional" value to be used for the two zones that represent the Bonneville regions crossing the east/west divide.[24] The final values for the Ninth Plan are shown in Table A - 8.[25]

Table A - 8: Transmission and Distribution Values for the Ninth Power Plan

Location	Transmission ($2024/ kw-year)	Distribution ($2024/ kw-year)	Combined ($2024/ kw-year)
West	$14.69	$24.18	$38.87
East	$4.77	$11.71	$16.48
Regional	$11.13	$19.71	$30.85

Modeling Zones

The Ninth Plan is the Council's first to represent the region in multiple modeling zones across all its tools. The modeling zones are based roughly on balancing authorities, but they are not intended to precisely reflect any single balancing authority. For the Council's demand forecast, the Council modeled 13 zones tied to the balancing authorities in the region (see Technical Appendix F). For the scenario modeling, the Council used 17 zones. These 17 zones generally reflect the balancing authorities, but split out the Bonneville and Puget Sound areas into more granular zones. This scenario modeling includes the zonal set up for GENESYS (the Council's adequacy tool), Aurora (the Council's tool for the west-wide market study), and OptGen/SDDP (the Council's regional capacity expansion model). More information on this modeling suite is available in Technical Appendix K – Modeling Framework. Discussion of how the Council leveraged the zonal information in the development of

[24] The Council's models use three different zones to represent the Bonneville balancing area: Bonneville OR, Bonneville WA, and Bonneville ID/MT. For the purposes of the transmission and distribution deferral values, the Council applied the Regional value to the Bonneville OR and Bonneville WA zones and applied the East value to the Bonneville ID/MT zone.
[25] Additional information on the build-up of these assumptions is available here: https://nwcouncil.box.com/v/ninthplant-ddeferral.

resource inputs is available in Technical Appendices G through J. Table A - 9 provides the modeling zones and the modeling abbreviations used throughout the Ninth Plan.

Table A - 9: Modeling Zones for Ninth Plan

Balancing Authority	Load Forecasting Zone	Scenario Modeling Zone
Avista Utilities	AVA	AVA
Bonneville Power Administration	BPA	BPA_IDMT
		BPA_OR
		BPA_WA
Chelan County PUD	CCPUD	CCPUD
Douglas County PUD	DCPUD	DCPUD
Grant County PUD	GCPUD	GCPUD
Idaho Power Company	IPCO	IPCO
NorthWestern Energy	NWMT	NWMT
PacifiCorp, East	PACE	PACE
PacifiCorp, West	PACW	PACW
Portland General Electric	PGE	PGE
Puget Sound Energy	PSE	PSE_Central
		PSE_North
		PSE_Olympia
Seattle City Light	SCL	SCL
Tacoma Power	TPWER	TPWER

Technical Appendix B: Existing System Parameters and Policies

Contents

Existing System 1
Defining the Pacific Northwest 1
Description of Existing Fleet by Generating Resource 2
WECC Existing System and Retirements 21
Greenhouse Gas Emissions from Generation 24
Existing Policies 27
Treatment of Policies in Ninth Power Plan 27
Federal 28
In-Region 30
WECC 39
Planning Under Uncertainty 44

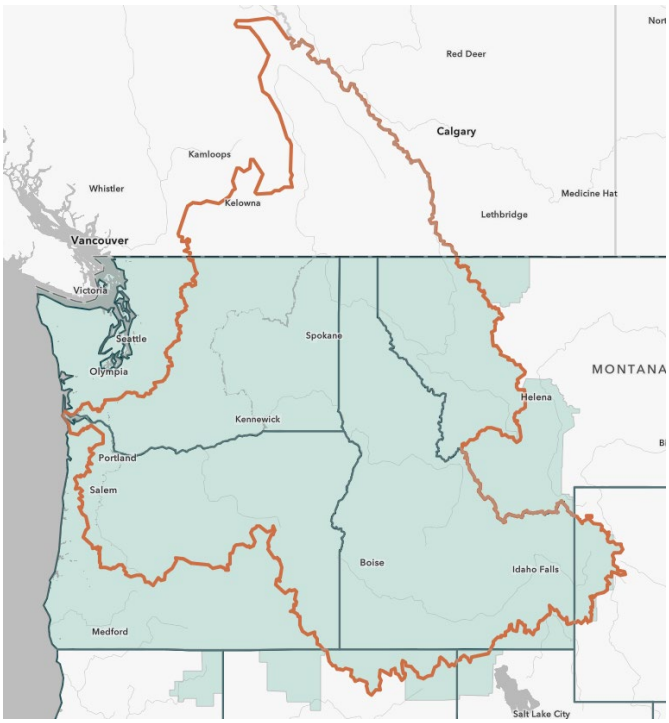
Existing System

The region finds itself in a state of flux, faced with higher load forecasts, steeper clean policy goals, an unpredictable federal policy landscape, a more variable generation mix, and uncertainty around how best to meet these challenges. One necessity of planning under such uncertainty is adequately representing what is known so that we can face the unknowns on firm footing. Identifying and accurately depicting the existing electric system helps us to define the parameters that our computer modeling will be solving. This section does that by documenting and characterizing operating resources as well as identifying and explaining relevant policies.

Defining the Pacific Northwest

The Northwest Power Act directs the Council to develop a power plan for the Pacific Northwest, referred subsequently as the "region." The Act defines this geographic area as the Columbia River basin plus the areas outside the basin where the Bonneville Power Administration sells firm power. That includes Oregon, Washington, Idaho, and the portion of Montana west of the Continental Divide.

Figure B - 1: Map of the Region as Defined by the Power Act



Description of Existing Fleet by Generating Resource

To understand what the capabilities of the existing system are to meet regional demand, we must determine which resources fall within that defined area. It is not always a case of where the resource is built. Some resources are built outside the region but serve regional load, or vice versa. The Council works with individual utilities to parse those plants so we can understand our footprint as best as possible.

The Council tracks all generating projects in the region in its project database.[1] The database includes project and technology specifications, operating parameters, historical annual energy, and much more. The database also includes an interactive map of power generation projects in the region.

For the Ninth Power Plan, the Council defines resources as operating or under construction, as well as owner-announced planned retirements and conversions. This represents the existing system capabilities and provides a sense of certainty from which we can project future needs. New resources available for the capital expansion model to select are discussed in Technical Appendix G – New Generating Resources.

[1] This workbook is updated dynamically and is available on the Council's website: https://www.nwcouncil.org/energy/energy-topics/power-supply.

Historical Generation

The history of regional generation is characterized by clear phases of development. The most important and lasting of these was the growth of the hydrosystem, with the bulk of the development occurring from the 1930s through the 1970s. The hydrosystem continues to provide the foundation of the region's energy landscape. In the wake of this large-scale development and in response to continued load growth, in the 1970s and 80s the region looked to coal and nuclear resources to supplement the hydro system. The late 90's saw the growth of natural gas in the region quickly followed in the mid-2000s by significant wind development. The rising cost of coal, cheap natural gas and growing awareness of the electricity sector's impact on climate change and the environment laid the groundwork for this shift. Starting in the late 2010s, the region looked to solar as an addition to the region's renewable fleet in an effort to meet growing load and tightening clean regulations. The most recent phase has seen the region looking to battery storage to increase resource adequacy and better optimize variable power from renewable generation.

Figure B - 2: Regional Resources Currently Operating

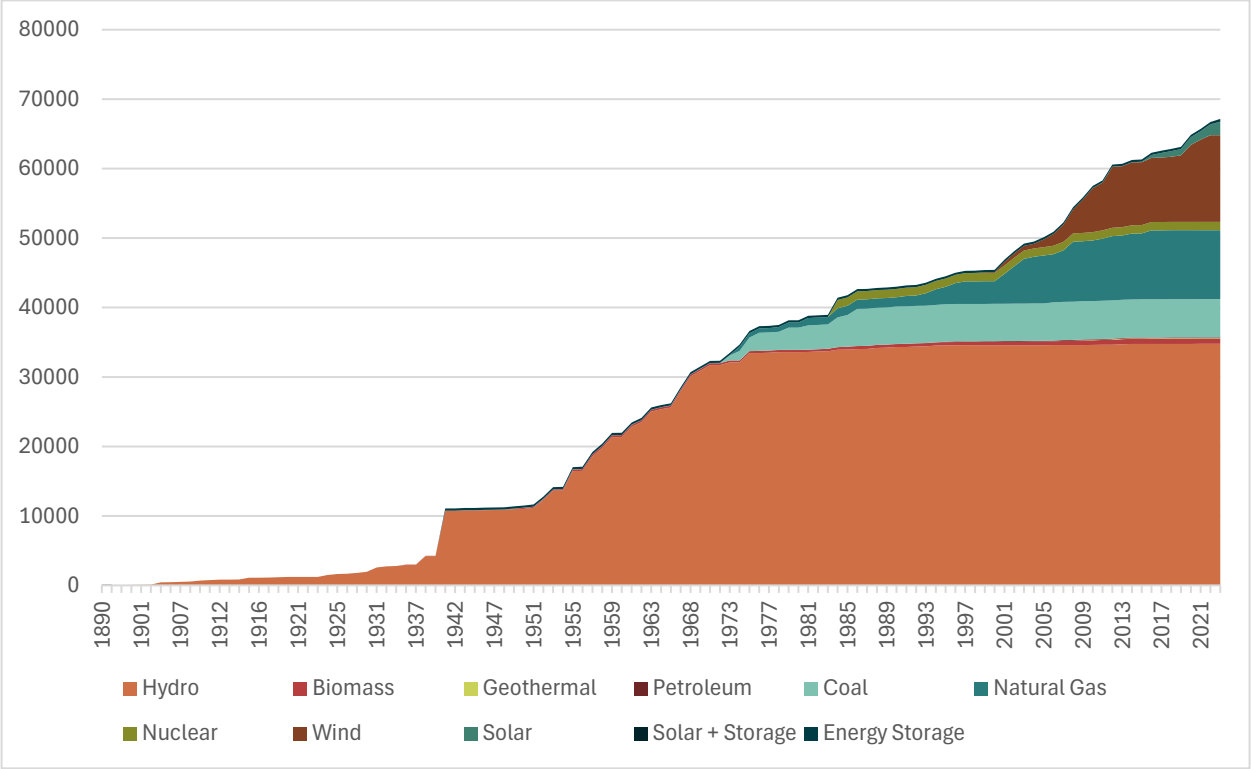
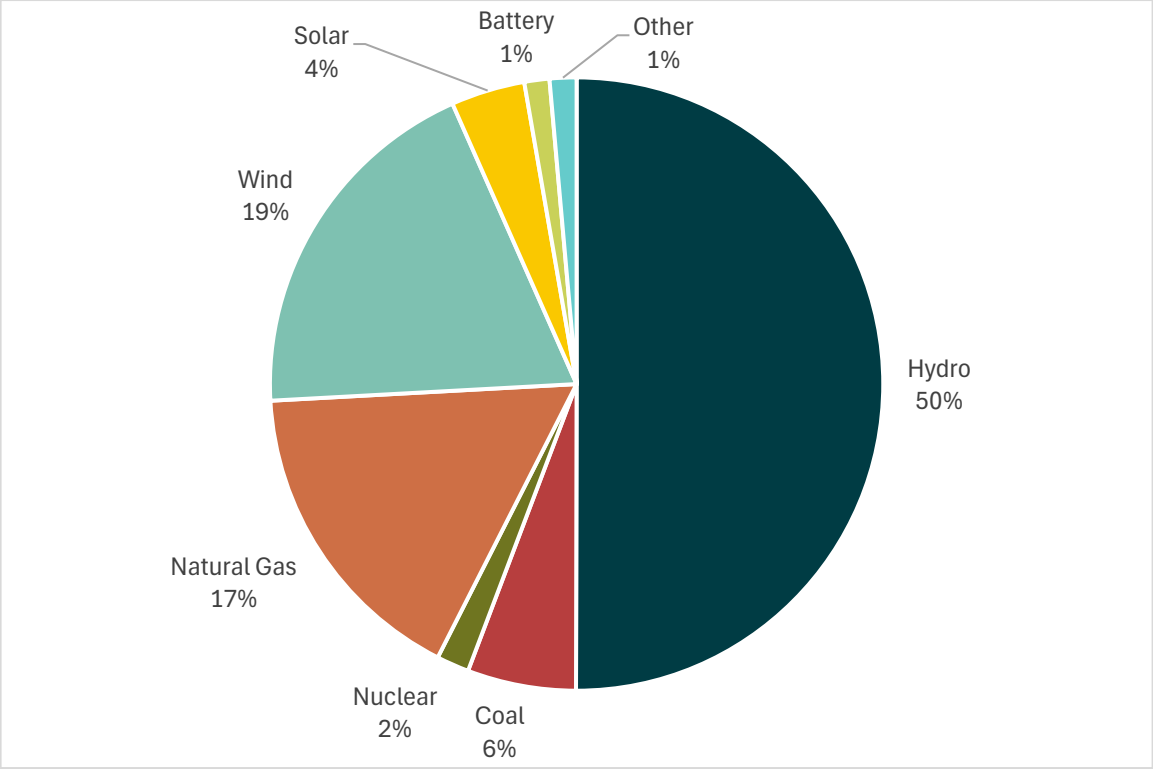


Figure B - 3: Current Installed Nameplate Capacity in the Region



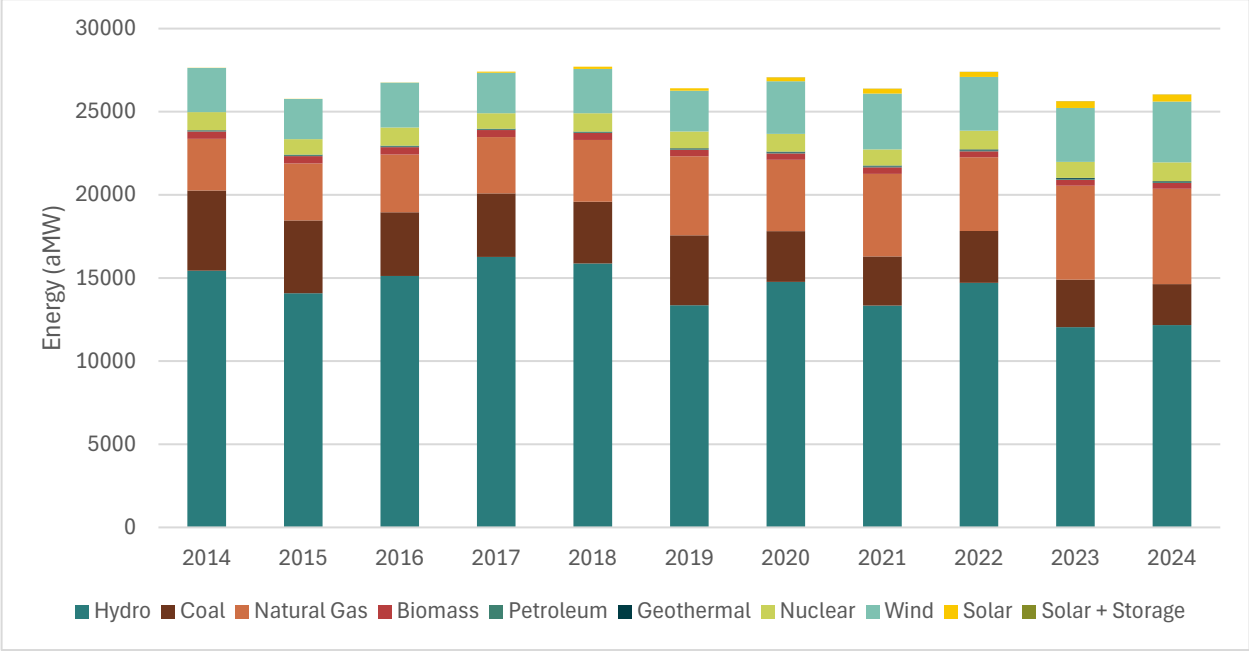
Historical Energy Production

The cumulative installed nameplate capacity of the region's existing system is not the same as the actual energy produced by that system. Hydro is the foundation of the region's energy supply and the rest of the system is utilized more or less to support the difference between load and hydro production. In high hydro years there is less need for supplemental generation from other sources, while lower hydro years rely more on the rest of the system, especially thermal production. As can be seen in Figure B - 4, 2017 and 2018 were higher hydro production years, and as a result there is less generation from other resources. On the opposite end of the spectrum, 2023 and 2024 were lower hydro years and the resulting compensation can be seen in higher generation from other regional resources. Beyond the hydro-driven variation, recent development trends can be seen in the year-to-year production with coal generation decreasing and renewables, especially solar, showing up more in recent years.

Additionally, most resources don't operate at their full capacity most of the time. Hydro, depending on the water year, is operating somewhere around 40% of the system's total capacity. Other renewables, by virtue of their variable fuel types, are similarly not providing the system with 100% capacity 100% of the time. A renewable plant's capacity factor is dependent on location, season, and time of day, but as an annual average over the past 10 years regional wind has had a capacity factor about 30% and solar has been at about 20%. Thermal generation fuel is generally available, so their utilization depends more on the economics of running those resources. Because thermal fuel is an additional cost, they are often the first to be curtailed to save on fuel cost. However, cost is not the only consideration, some thermal resources are less flexible than others. Nuclear plants, for example,

are difficult to turn on and off, while a gas plant, depending on the technology type, can be ramped up and down relatively easily. The region's remaining nuclear plant operates at about 90% capacity, while natural gas is utilized more flexibly, with an average annual capacity factor of about 50%.

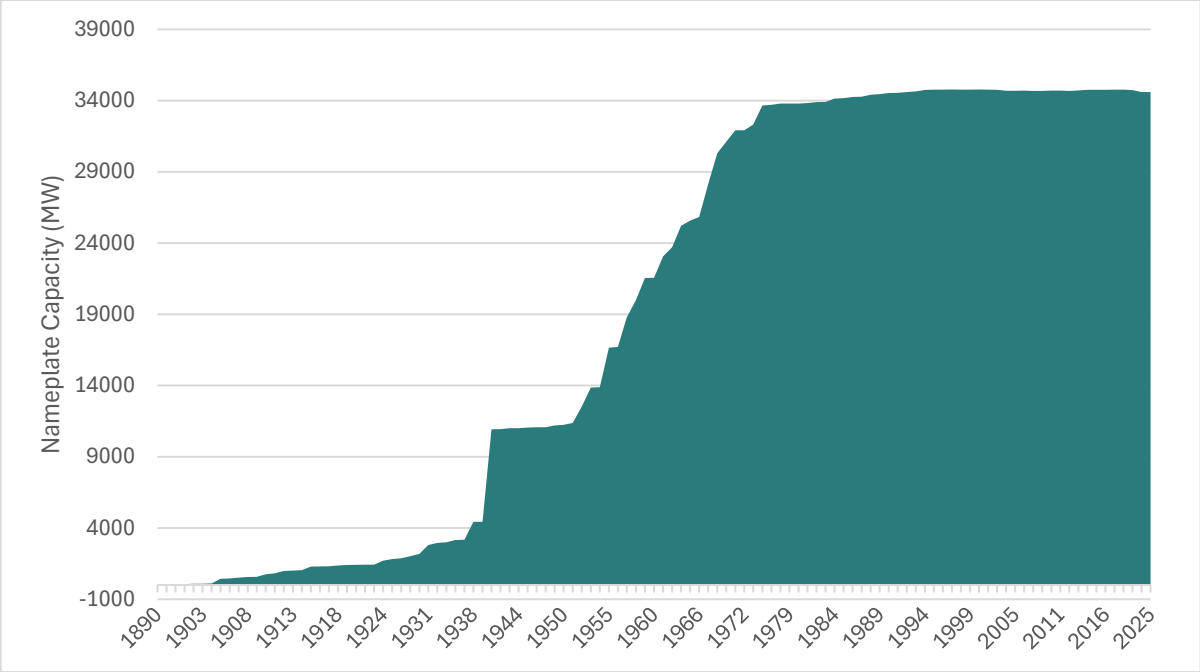
Figure B - 4: Historical Annual Energy Production



Hydropower

The Columbia River and its associated tributaries comprise one of the major economic and environmental resources in the Pacific Northwest. Originating in the Rocky Mountains in Canada, the mainstem Columbia River extends a total of 1,243 miles to the Pacific Ocean. Beginning in the 1930s, development of the Columbia Basin hydrosystem included over 250 hydropower dams and about 200 non-powered dams (built for other purposes such as irrigation and flood control). Today, the Columbia River Basin hydropower system delivers carbon-free, renewable energy that, on average, supplies about half of the electricity generation in the region. Figure B - 5 shows the growth of hydroelectric power in the region since 1890. This figure does not show the hydropower retirements in the system due to scale, but the region has seen about 400MWs of hydro retirement.

Figure B - 5: Regional Hydroelectric Nameplate Capacity Installed Over Time



Beginning in 1980, the operational flexibility and generating capability of the Columbia River Basin hydropower system has been reduced, due in part to efforts to better protect fish and wildlife.[2] Over the past forty years, the pattern of reservoir storage and release has shifted some winter river flow into the spring and summer periods for juvenile salmon migration. Minimum reservoir elevations have additionally been modified to provide better habitat and food supplies for resident fish. Other operational constraints on the system come from flood control, irrigation, recreation, and transportation to name a few.

Coal

Following the development of the Columbia River hydropower system, coal and nuclear power were viewed as the most economical new sources of electricity. Between 1968 and 1986, Northwest utilities brought into service 14 coal-fired units at six sites: Boardman (Oregon), Centralia (Washington), Colstrip (Montana), J.E. Corette (Montana), Jim Bridger (Wyoming), and North Valmy

[2] Under the Northwest Power Act, the Council is required to develop a Fish and Wildlife Program to protect, mitigate, and enhance the fish and wildlife affected by the development and operation of any hydroelectric project in the region. The Program is also expected to establish objectives for the development and operation of such projects in the region in a manned designed to protect, mitigate, and enhance fish and wildlife [§4(h)(2)(A), 94 Stat. 2708]. The Northwest Power Act also calls on the Council to "set forth a general scheme for implementing conservation measures and developing resources … to reduce or meet the Administrators obligations" [§4(e)(2), 94 Stat. 2708]. These obligations include Bonneville's obligations to implement the Council's Fish and Wildlife Program. Therefore, the Act intended that there would be some deration of the system for the benefit of fish and wildlife, and it is the task of the power plan to make up any resulting power needs.

(Nevada). At its height, the region's coal capacity (including several smaller coal units) totaled around 7,300 megawatts.

In recent years, the adoption of more clean policies as well as the dropping prices of alternative resources like natural gas and renewables has reduced the role of coal in the region. In the 2021 Power Plan, the Council analyzed the many owner-announced coal retirements without planned replacements. Many coal plant owners have since scrapped their retirement plans and will instead convert the plants to natural gas. Coal-to-gas conversions use the existing boiler with new natural gas burners and can be a quick way to maintain similar capacity while reducing emissions and fuel costs. However, converted coal plants maintain a similar heat rate and are therefore less efficient at turning natural gas into energy than other new natural gas plant technologies. Many utilities consider these conversions to provide an interim solution as they seek to develop and integrate other new generation onto the system. Table B - 1 shows the in-region coal plants included in the Ninth Plan and the assumed plans for conversion. Table B - 2 shows total operating coal capacity in the region as compared to retired and converted capacity.

Table B - 1: In-Region Coal

Coal Unit	Nameplate Capacity (MW)	Fuel	Announced Retirement Date	Notes
Centralia 2	730	Coal	n/a	Conversion expected late 2028
Jim Bridger 1	608	Gas Conversion	n/a	Converted in 2024
Jim Bridger 2	617	Gas Conversion	n/a	Converted in 2024
North Valmy 1	277	Gas Conversion	n/a	Conversion expected in 2026
North Valmy 2	289	Gas Conversion	n/a	Conversion expected in 2026
Colstrip 3	778	Coal	n/a	
Colstrip 4	778	Coal	n/a	
Jim Bridger 3	608	Coal w/ CCS	n/a	Adding CCS in 2030
Jim Bridger 4	608	Coal w/ CCS	n/a	Adding CCS in 2030

Table B - 2: In-Region Coal Capacity

	Nameplate Capacity (MW)
Retired Coal	3,060.8
Operating Coal	3,026.7
Converted Coal (incl. planned)	1,792

Nuclear

The region's first nuclear generating project – the Hanford Generating Project in Hanford, Washington, the site of plutonium production for atomic weapons used in World War II – was authorized by Congress in 1958 and came online in 1966. Around this time, regional utilities initiated the construction of five new nuclear power plants - part of the ill-fated and very expensive Hydro-Thermal Power Program, a plan to use thermal resources like coal and nuclear for baseload generation, and to use the flexibility of the hydropower system to meet daily and seasonal peaks in demand. Only two of the proposed nuclear projects were eventually constructed and operated in the region. Trojan, in Oregon, was finished in 1976 and the Columbia Generating Station (CGS) in Washington, began operations in 1984.[3]

Hanford operated until 1987, when it was placed on standby and eventually shut down in 1994. Trojan was permanently shut down in 1993, when it was deemed no longer cost competitive, and was demolished in 2006. Trojan's retirement and eventual demolishing was also a reaction to years of organized anti-nuclear pushback against the plant. These sentiments were codified into law in 1980 by Oregon's Ballot Measure 7, which banned the construction of new nuclear reactors without a permanent, federal repository for high-level nuclear waste and the approval of Oregon voters.[4]

Today, CGS is the only remaining nuclear plant operating in the region. Owned and operated by Energy Northwest, CGS is licensed to run through 2043, after the Nuclear Regulatory Commission granted a 20-year renewal to CGS's original 40-year operating license. CGS has a gross capacity of about 1,200 megawatts and provides on average between 950–1,100 average megawatts of energy to the region annually, depending on the refueling schedule (every other year, CGS schedules a refueling outage coinciding with the spring runoff to tackle refueling and maintenance projects on site). In May 2025, Bonneville approved an extended power uprate to CGS, which would increase generating capacity by around 160 megawatts by 2031.

The recent need for new resources, especially the perceived need for new baseload resources, has created interest in nuclear. Plants in other parts of the U.S. are being repowered, and there is ongoing

[3] A more detailed history can be found here: https://www.nwcouncil.org/reports/columbia-river-history/hydrothermal
[4] ORS 469.590 to 469.599 Siting of Nuclear-Fueled Thermal Power Plants: https://www.oregonlegislature.gov/bills_laws/ors/ors469.html.

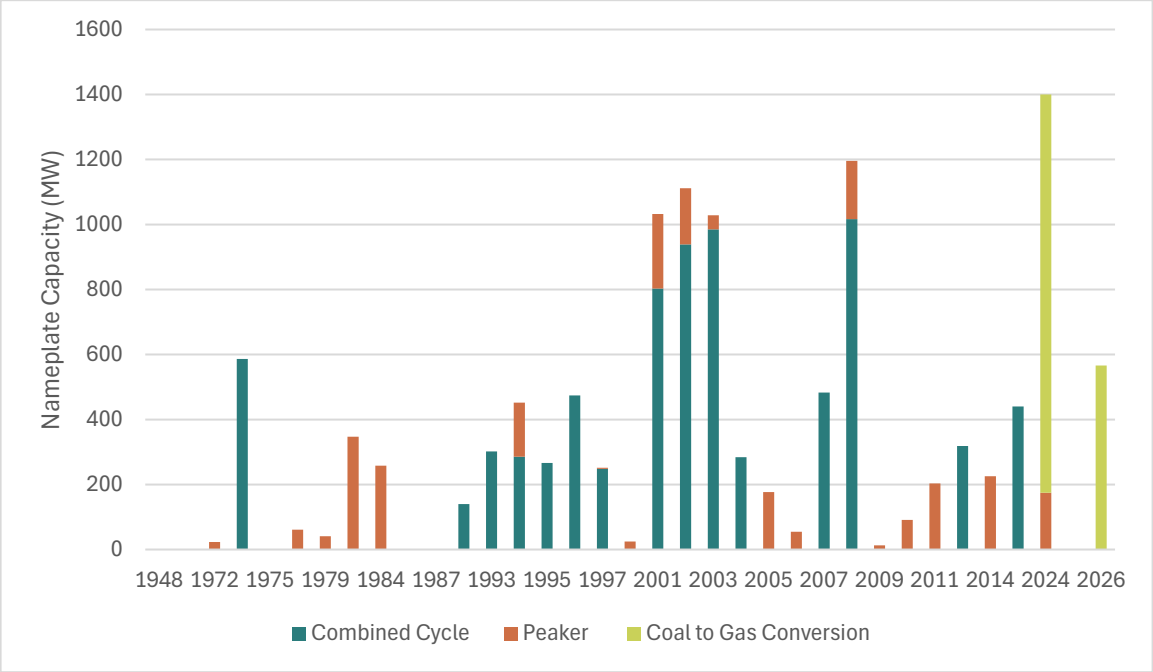
interest in new applications of nuclear technology. These emerging technologies are discussed further in Technical Appendix G – New Generating Resources.

Natural Gas

The first natural gas-fired baseload power plant developed in the region was Portland General Electric's 600 MW Beaver combined cycle power plant in 1974. A few gas peaking plants, primarily frame simple cycle combustion turbines, were constructed in the early 1980s, but it wasn't until the early 1990s that natural gas power plant development really gained steam. General Electric released its F-class frame unit, a machine with increased reliability and efficiency, and combined with low gas prices, the region saw a shift in development from coal to gas plants. A second wave of gas plant development by independent power producers came in response to the West Coast electricity crisis[5] in the early 2000s.

In recent years, the development of gas peaking plants (simple cycle and reciprocating engine)[6] in the Pacific Northwest and elsewhere can be attributed in part to the need for additional flexibility and efficiency in the power system to supplement and integrate variable energy resources such as wind and solar.

Figure B - 6: Types of Gas Plant Built in the Region Over Time



[5] More on that history here: https://www.nwcouncil.org/reports/columbia-river-history/energycrisis.
[6] These plant types are described in more detail in Technical Appendix G – New Generating Resources.

Biomass

Biomass includes a variety of fuels, including pulp and paper, woody residues (forest, logging, and mill residues), landfill gas, municipal solid waste, animal waste, and wastewater treatment plant digester gas. There are about 750 megawatts of installed biomass nameplate capacity in the Pacific Northwest. The majority of the region's biomass capacity burns fuel from spent pulping liquor and woody residues. In recent years, there have been several small (on average three megawatts or less) animal waste and landfill gas plants developed on existing dairy farms and landfill operations. With the economic recession in the late 2000s, several of the region's paper and textile plants have shut down, greatly reducing the supply of pulping liquor for pulp and paper biomass plants.

Industrial Cogeneration

Cogeneration, or combined heat and power plants produce both electricity and thermal or mechanical energy for industrial processes, space conditioning, or hot water. The Power Act[7] gives first priority to conservation, second priority to renewable resources, and third to generating resources using waste heat. Industrial cogen falls under this third priority category. In the Pacific Northwest, there are different types of industrial cogeneration, namely biomass and natural gas plants. Industrial cogeneration in the forest products industry has long been a component of Pacific Northwest electric power generation. These plants include chemical recovery boilers in the pulp and paper industry, and power boilers fired by wood residues, fuel oil, and gas in both the pulp and paper and lumber and wood products sectors. Gas-fired combustion turbines have also been installed as industrial cogeneration units, oftentimes with the waste heat (steam) being used for secondary heating purposes.

As demand for paper and newsprint has declined over the past decade, several local wood product manufacturers have suspended operations. Without the biofuel waste produced from the factories, the biomass plants have been forced to close as well. Many industrial cogeneration plants do not sell power offsite and/or generate power only when fuel costs are favorable. Therefore a precise inventory of operating industrial cogeneration plants is difficult to obtain. For these purposes, the known plants have been included in the generating capacity of the primary resource, for example biomass and natural gas.

Geothermal

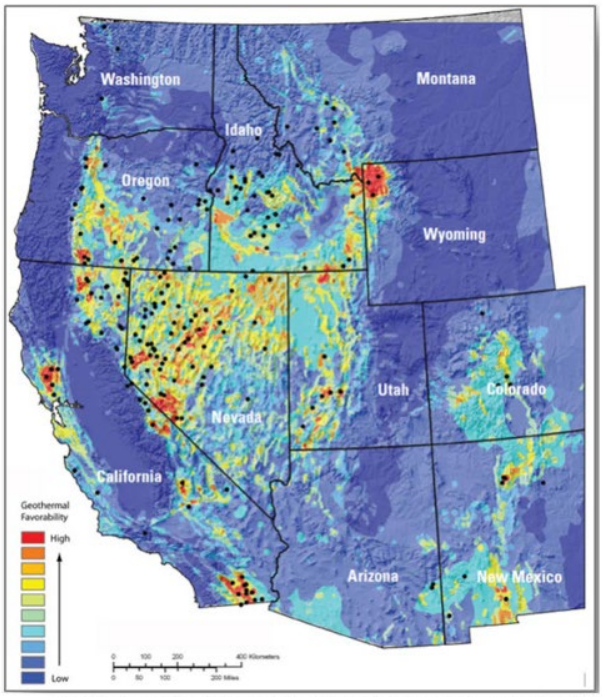
Geothermal is a renewable, clean energy resource with zero or low carbon emissions – depending on the technology used (flash steam technology emits minimal excess steam; dry steam and binary emit zero emissions). The Pacific Northwest is home to a significant, naturally occurring geothermal resource (heat + water + permeability) – especially in Southern Oregon and Idaho – and yet, development has been limited so far.[8] Between 2007 and 2015, four geothermal projects were

[7] Northwest Power Act, §4(e)(1), 94 Stat. 2705.
[8] USGS Assessment of Geothermal Resources: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.

developed in the region, totaling about 50 megawatts installed nameplate capacity. Each project utilizes binary, closed-loop technology – the hot water and steam from the production well is used to boil a working fluid that is contained in a separate, closed-loop process, which is then vaporized to steam to rotate the turbine.

Since then, there have been several efforts to explore and develop more geothermal resources in the region, but none have yet come to bear. There is significant risk involved with any geothermal development, it requires high upfront capital investment which often doesn't result in discovery of a viable resource. Recent developments in drilling technology that make discovery more certain have renewed excitement for the technology. These advancements are further explored in Technical Appendix G – New Generating Resources.

Figure B - 7: Map of Geothermal Favorability in the West[9]



Map of the favorability of occurrence for geothermal resources in the western United States
Warmer colors equate with higher favorability. Identified geothermal systems are represented by black dots.
Source: Williams et al. 2008

Wind

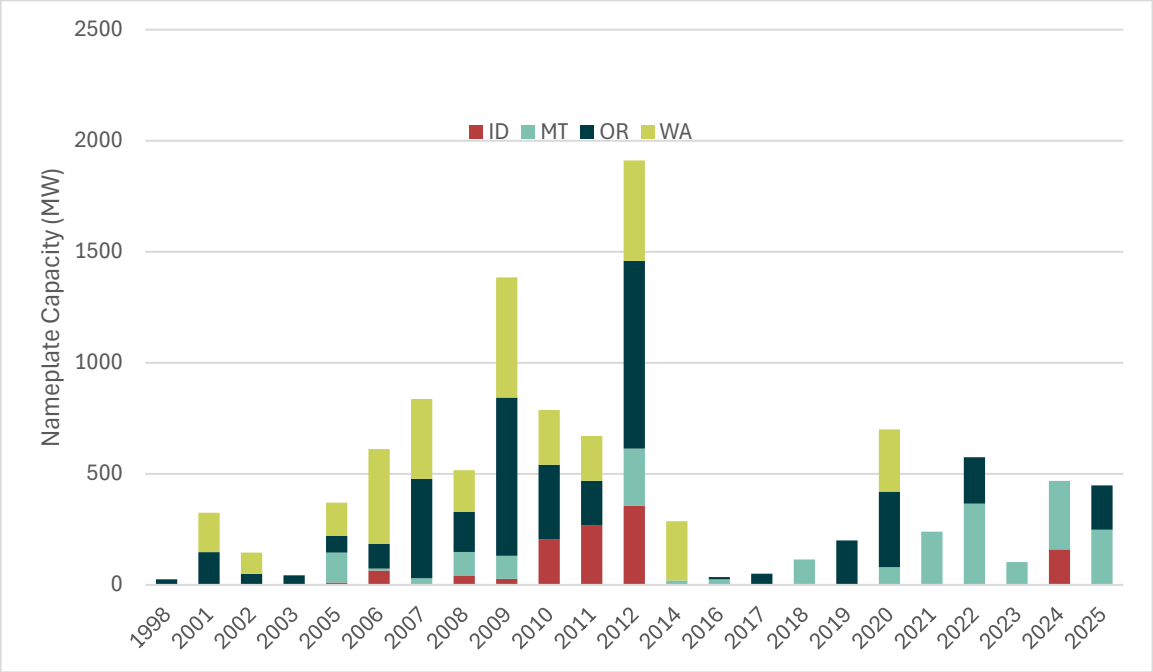
Utility-scale wind first started appearing in the region in the late 1990s and early 2000s. With the adoption of state renewable portfolio standards (RPS) in the mid-2000s, wind development ramped up significantly, peaking in 2012 - a record year for wind development in the region.

[9] USGS assessment of geothermal resources: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.

Driven by renewable policies, wind was adopted early as a renewable resource in the region. Many of the best resource areas are already developed, but new technologies are opening up more locales. Compared to solar, wind has higher annual capacity factors, but more variable generation as it is less predictable than the rise and set of the sun.

Technological advancements in hub heights and rotor diameters have allowed new wind turbines to access greater wind speeds at higher elevations and to "sweep" more wind through the blades, unlocking and reaching more wind resources than ever before. These innovations have helped broaden the application and location of wind projects. Wind speeds are classified by the International Electrotechnical Commission (IEC) on a scale from 1 to 4, with class 1 being a high-speed wind resource and class 4 being a very low speed wind. (These classifications are based on site wind speed, extreme gusts, and turbulence.) When wind development kicked off in the 2000's, many of the locations were class 1 or 2 sites, to take advantage of the best wind resources available (the low hanging fruit). Now, new developments are occurring in lower classified wind speed areas with turbines designed to maximize the wind resource available – even at low or very low wind speed classifications. In addition, advancements in the electronic components of the turbine – such as the gearbox – allow for greater control, efficiency, and reliability, and a decrease in fixed operating and maintenance costs.

Figure B - 8: Regional Annual Wind Development

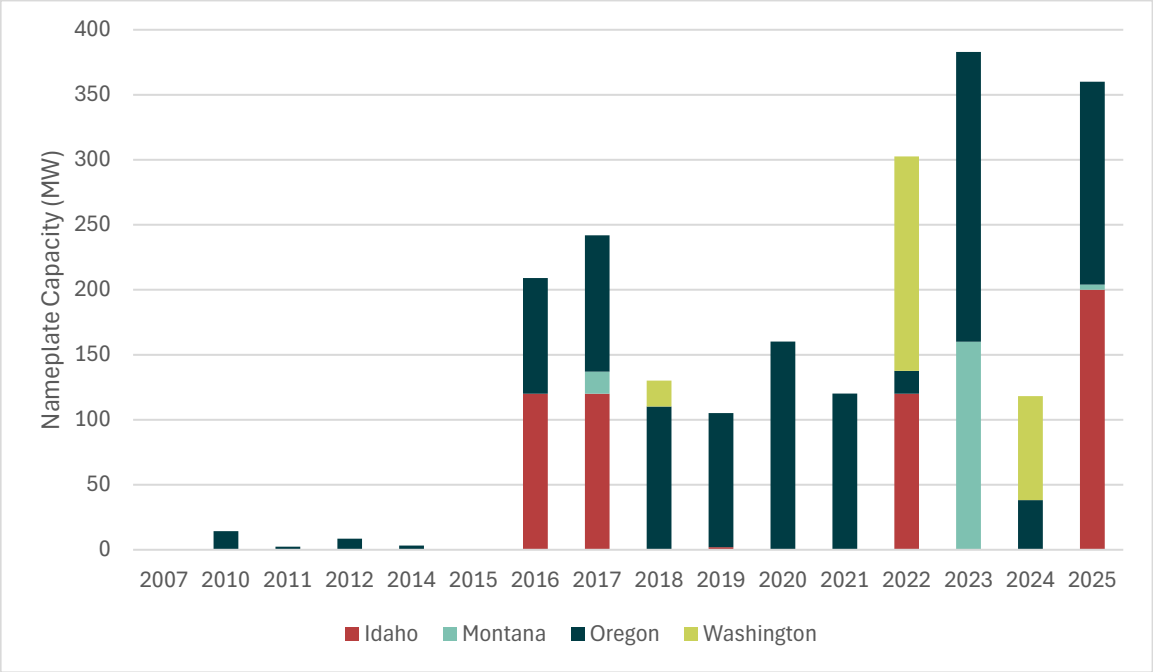


Solar

Solar photovoltaics are a newer technology relative to those already described, but installation of solar in the region has been accelerating in recent years. Early solar development in the country primarily occurred in places with a better solar resource like California and the desert Southwest. A

flood of cheap solar energy onto the market from those sunnier locations meant that the lower capacity solar of the Pacific Northwest wasn't needed, discouraging early solar development in the region. However, this has changed in recent years. Load has continued to grow, clean policies have gotten more stringent, and the cost of solar has decreased significantly, with solar becoming the lowest-cost new generating resource option in the region on a levelized cost of energy basis. Accordingly, the region is seeing increased solar development.

Figure B - 9: Regional Installed Solar & Co-Located Solar + Battery Capacity



Storage

Storage resources are the latest phase of regional electric system development, with the installed capacity in the region increasing steeply since the Council's 2021 Power Plan. In 2024 and 2025, there region built 1000 MW of battery storage. Storage resources capture and store energy generated at one time to be discharged and used at another. They provide a wealth of benefits that align with modern grid needs. They can deliver variable energy integration, load shifting, transmission and distribution deferral, ancillary services, energy arbitrage, and emergency backup.

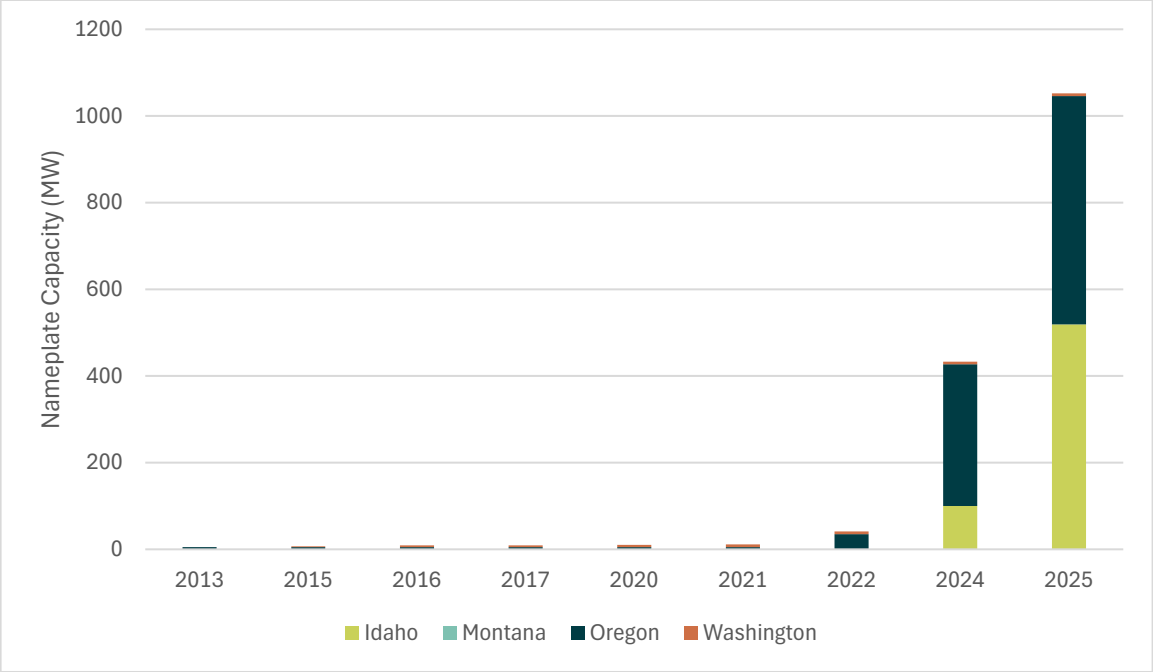
Lithium-Ion Batteries

The most common storage resource built in the region are lithium-ion batteries. The hydro system has insulated the region from the need for much storage up this point. However, as more renewables have come online, batteries allow for better balancing of their variable generation, shifting that production to better match load. Larger loads, more variable resources, and increasing clean policy requirements seem poised to continue to drive more battery development. Figure B - 10: Regional Battery InstallationsFigure B - 10 shows the installed battery storage capacity in the region. It illustrates the recency of the technology in the region, with only 55 MWs built in Oregon and 6.2 MW in Washington

from 2013 to 2022, and then a steep increase in particularly Oregon and Idaho of over 1500 MW in 2024 and 2025.

This need is also driving interest in alternative storage technologies beyond the most common 4-hour lithium-ion batteries (discussed further in Technical Appendix G – New Generating Resources).

Figure B - 10: Regional Battery Installations[10]



Pumped Storage

Pumped Storage is a resource that is constrained by geography, requiring suitable topography and geologic conditions for constructing upper and lower reservoirs at different elevations. Despite the Pacific Northwest's prolific hydro resource, the region has not seen much pumped storage development. A proposed project between Banks Lake and Lake Roosevelt near the Grand Coulee Dam has seen recent development progress, but is still in very early stages.[11] Most pumped storage in the country was built in the 1970's, and there hasn't been much development since, despite many projects in the development and permitting pipeline.

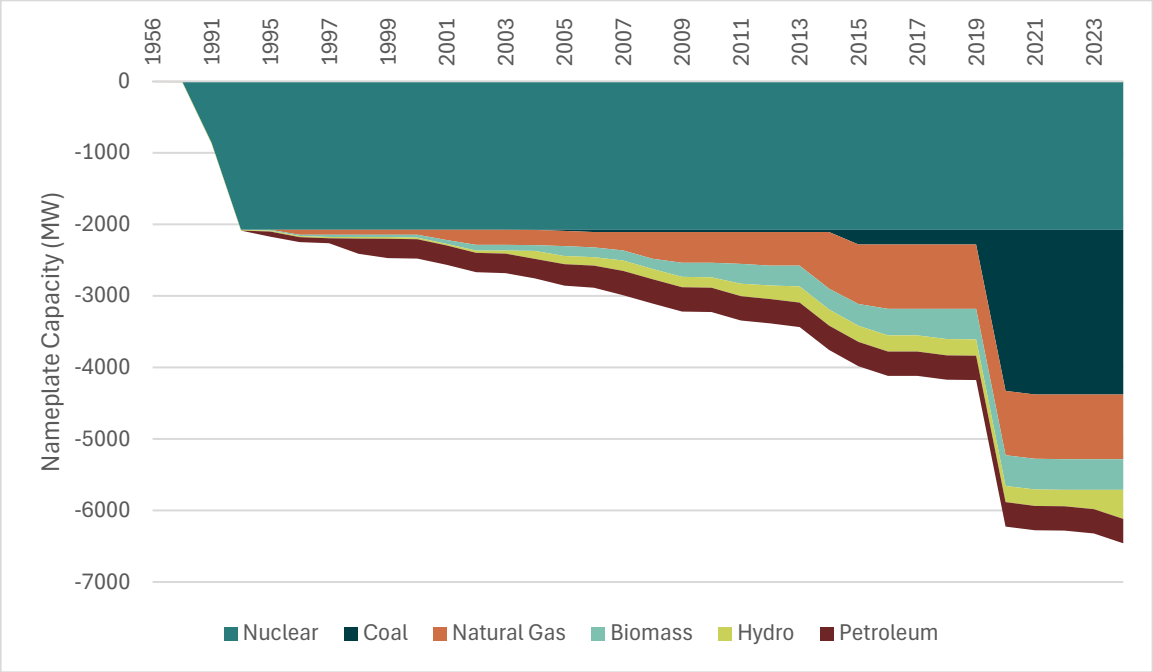
Generation Retirements

The evolving electric power system of the region also includes resource retirements. These are captured in the existing system to ensure the Council power plan accounts for any new generation

[10] This includes batteries built on the same site as solar PV. About 132 MW of the over 1000 MW of batteries installed in the region are collocated.
[11] https://www.usbr.gov/pn/programs/lopp/bankslake.

needed to offset retirements and to accurately represent the capabilities of the region's resources. The wide teal area in Figure B - 11 shows the retirement of Hanford and Trojan nuclear plants in 1991 and 1993 respectively. After that it shows some natural gas retirements in the 2000's to early 2010's and most recently coal retirements starting in 2020.

Figure B - 11: Recent Regional Resource Retirements



Demand Side Resource

Demand side resources are an important part of our existing system. Today, the three primary demand side resources that impact the power system are conservation, demand response, and rooftop solar.

Conservation

The Northwest Power Act directed the Council and the region to consider and prioritize conservation as a resource. Since the 1980s the region has been running conservation programs and accumulating savings from these programs. The Council's 2024 Regional Conservation Progress[12] survey reported that the region has acquired over 8,000 aMW since 1980, or enough electricity as the average production of three Grand Coulee dams. Because of these acquisitions, the region has avoided having to build generating resources to provide that electricity. The Ninth Plan, like all prior plans, includes a

[12] The Regional Conservation Progress Report: https://rtf.nwcouncil.org/about-rtf/conservation-achievements/2024.

detailed assessment of new conservation potential for the Northwest (See Technical Appendix H – Conservation Methodology and Potential).

Demand Response

Because the Northwest power system has historically been energy constrained (not capacity constrained), demand response (DR) is a relatively untapped resource in the region. DR programs have been around the region for a while, primarily in the agriculture sector, but have not been widespread. However, in recent years, the need for new capacity has become increasingly evident by individual utilities, who have begun developing and offering DR programs. DR has also been more prominent in the Council's Seventh and 2021 Power Plans which have shown the region has a need for cost-effectively implementing DR. As of the end of 2023, the region reported 687 MW of DR actively being implemented. The Ninth Plan includes a robust supply and analysis of DR products (See Technical Appendix I – Demand Response Methodology and Potential).

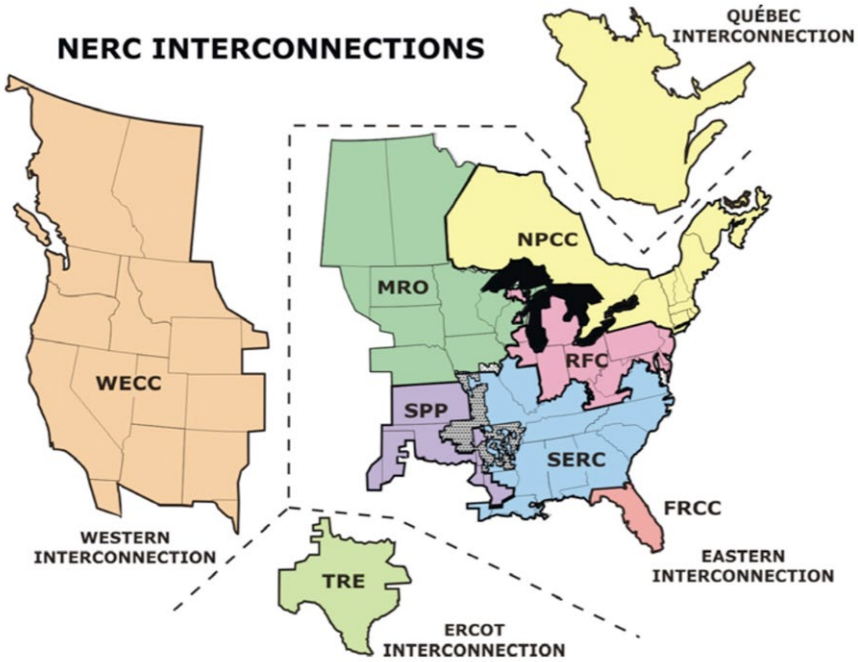
Rooftop Solar

Rooftop solar installations in the Northwest have been steadily climbing. In prior power plans, rooftop solar has been included as a demand reduction in the load forecast, but has not been developed as a new resource to compete with other supply and demand side resources. This is because the costs were relatively high, and the impacts were low. Both of those have now changed: costs have come down substantially and installations have increased. In 2011, there were 4 MW of rooftop solar capacity installed and that number has grown to over 1300 MW (forecasted) in 2025. The Ninth Plan includes a potential assessment of new rooftop solar in both the residential and commercial sectors (See Technical Appendix J – Rooftop Solar Methodology and Potential).

Transmission

The Pacific Northwest transmission grid is a part of the Western Interconnection, one of three major National Energy Regulatory Commission (NERC) grid interconnections in the continental United States, encompassing all or parts of the states and provinces west of the Rocky Mountains to the Pacific Ocean, and Northern Baja California. The other two interconnections are the Eastern Interconnect which covers states and provinces east of the Rocky Mountains to the Atlantic Ocean and the Electric Reliability Council of Texas (ERCOT) Interconnection which covers most of Texas. The transmission system is composed of major alternating current (AC) and direct current (DC) high voltage lines, distribution lines, substations, transformers, source generators, and delivery points or load centers.

Figure B - 12: Map of National Energy Regulatory Commission Interconnections[13]



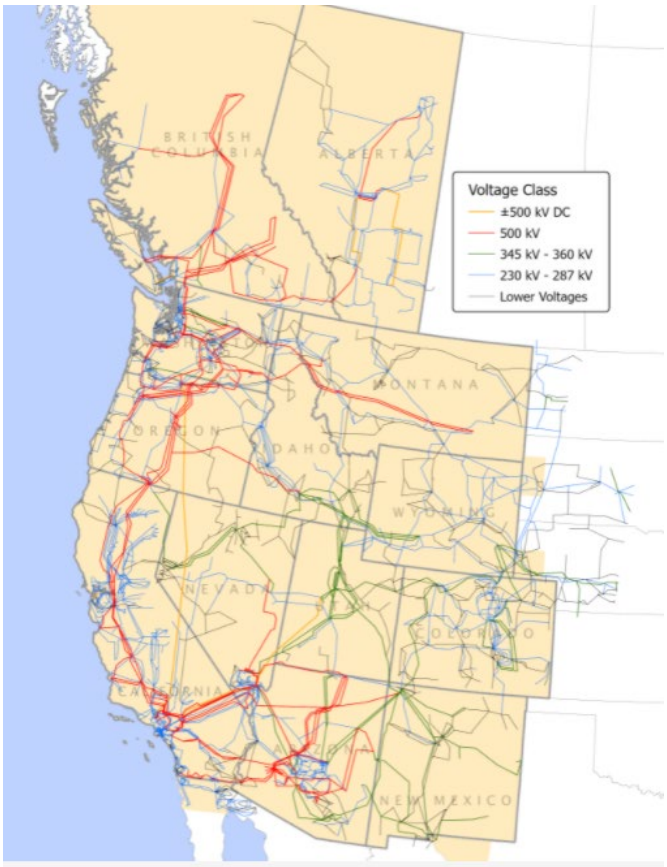
Northwest utilites are connected to the greater West through interties into California, BC, and the Rocky Mountain area. According to the Western Electricity Coordinating Council (WECC) ,[14] the Western Interconnection comprises roughly 136,000 miles of transmission lines.[15] The system was strategically developed to connect the major load centers with remote resources, and in particular in the Pacific Northwest, to connect the hydropower dams to high-voltage transmission lines in order to support the transfer capability of seasonal energy.

[13] https://www.nerc.com/who-we-are/key-players.

[14] The WECC acronym is used to describe both the Western Interconnect and the Western Electricity Coordinating Council which have overlapping definitions but are technically different. The Western Interconnect is a grid region that covers states from the Pacific Ocean to the Rocky Mountains. The Western Electricity Coordinating Council a non-profit corporation that exists to ensure a reliable Bulk Electric System in the geographic area known as the Western Interconnection.

[15] https://wecc-spdp-weccgeo.hub.arcgis.com/pages/transmission-availability.

Figure B - 13: Western Interconnection[16]



While the Pacific Northwest does not have a single regional transmission operator (RTO) or independent system operator (ISO), there are balancing authorities (BA) that ensure the dispatch of generation to the electricity grid meets energy demand (load) at any given time. Balancing authorities work independently to balance the needs within their designated footprint, but there are coordinated agreements among BAs to collaborate on reserve sharing, transmission maintenance, and expansion activities. A recent iteration of such a collaborative body is the Western Transmission Expansion Coalition (WestTEC), which is serving as the source for much of the Ninth Plan's future transmission assumptions, discussed in more detail in the uncertainty section at the end of this appendix.

In general terms, the Pacific Northwest power system operates within a bilateral (decentralized) transmission market in which the developer or owner of a generating resource must typically secure or hold the rights to a long-term firm transmission contract in order to proceed with constructing and selling the output of the resource. A bilateral contract can create price stability for both the buyer and the seller. A long-term firm contract is essentially a reservation for transmission capacity between specific points, for all hours of the day. While there are some conditional firm capacity contracts, they are limited and only available on a short-term basis. A conditional firm contract allows a resource to

[16] Ibid

access the grid, but the operator reserves the right to curtail the reservation under specified conditions in favor of long-term firm contracts.

Long-term firm contracts are maintained regardless of whether or not the capacity is physically used (i.e. whether or not there is generation at a given hour). However, FERC Order 889 requires that all unused transmission capacity must be marketed on the Open Access Same-Time Information System (OASIS) for short-term duration use. This can have limited value to developers who may need a firm transmission deliverability guarantee to secure financing and begin construction.

The Bonneville Power Administration owns the majority of the transmission system in the Pacific Northwest, although there are some utility and energy service supplier owners as well. There is currently limited available transmission capacity (ATC) within the Pacific Northwest grid, as much of the capacity is tied up in long-term firm contracts. To secure transmission, resources in the region must proceed through an interconnection request as well as a parallel transmission service request with a specific point of receipt (POR) and point of delivery (POD). As major projects retire, additional capacity may open up on certain paths and transmission rights could be resold or developed by the owners.

When Bonneville receives transmission service requests to bring generation online from a certain point on the system, they enter a Transmission Service Request and Expansion Process (TSEP) queue and are analyzed as "clusters" where projects in similar areas are grouped together. One issue Bonneville and any transmission provider in a bilateral market faces is that through the OATT process, they cannot make a judgement call on which project requesting transmission service will move forward out of the group. Rather, they either process the requests serially under the assumption that requests earlier in the queue will actually come online (this is not always the case) or when analyzing a cluster study they assume that all of the requests come online together. This can be problematic for a number of reasons. As an illustrative (and oversimplified) example, thousands of megawatts of capacity (across many projects) enter the queue in response to one request for proposals (RFP) for 100 megawatts capacity where there is currently 99 megawatts of available transfer capacity (ATC). These projects are studied in aggregation (thousands of megawatts vs. 100 megawatts of need identified in the RFP) as if they are all going to be built, rather than one winning bid. This can result in a study showing the need for significant system upgrades to meet the thousands of megawatts in the queue, rather than the 1 megawatt needed (in addition to the 99 megawatts ATC) to meet the RFP. Thus, the result is that the transmission offer is not made to any of the projects in the queue.

Project developers can also experience significant delays to project construction due to long transmission request queues. If developers were able to build (and secure funding) under the assumption that they could purchase the unused short-term physical capacity tied up in long-term firm contracts through OASIS, more projects could be developed and the transmission grid could be better used. This is currently not a reality for many project developers who require firm transmission guarantees to proceed. Transmission system expansion and upgrades are long-term projects that can be very expensive and intensive to complete.

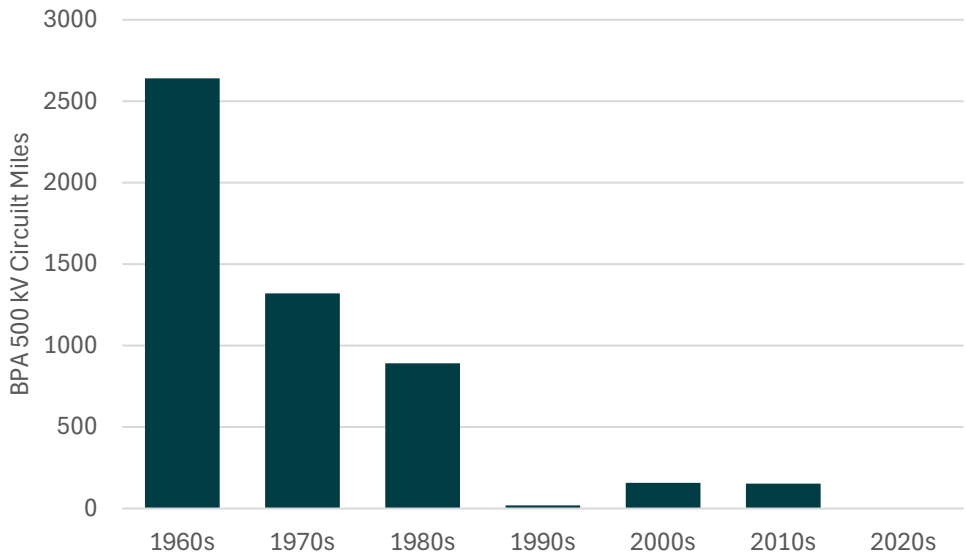
These contractual constraints and complications of the transmission system are often a barrier for building and connecting new resources to the grid, however, the Council's models only take physical

transmission limits into consideration. If there is space on a line, regardless of contractual availability, the models will allow resources to be built to fill that space. This simplifies modeling and the Council considers this ideal use of the transmission system, unencumbered by contractual obligations, to be appropriate at the regional-level that the power plan operates.

Transmission in the Ninth Plan

Much of the region's existing transmission system was built in the 1960s through the 1980s, as illustrated in Figure B - 14 below. This stagnation in new transmission development has become increasingly pressing in recent years, as increasing loads and more dispersed generation asks more of the aging system.

Figure B - 14: PNW Transmission Build Out by Decade[17]



The Ninth Plan intends to explore how the pace of transmission development might impact new resource selection through scenario analysis.[18] However, this need for new transmission is already prompting action in the region, with a number of new projects planned and underway. In the Plan, any transmission that already exists or is under construction by the start of the action period[19] is included in the representation of existing transmission. Projects under construction and therefore considered in the existing system are described in Table B - 3 below.

[17] https://www.nwcouncil.org/fs/18429/2023_08_3.pdf.
[18] Technical Appendix N – Scenario Modeling and Results.
[19] 2027-2032.

Table B - 3: New & Under Construction Transmission Projects Included in Existing Transmission

Planned Transmission	Capacity	Path	Online Date
Ten West Link	3200 MW	SCE to APS	2024
SunZia	3000 MW	PNM to APS	2026
Transwest Express	3000 MW	WAPA Wyoming to PACE UT	2027
	1500 MW	PACE UT to Nev South	2027
SWIP North	1700 MW	IP to North Nevada	2027
B2H	1000 MW	IP to BPA_OR	2026

WECC Existing System and Retirements

The WECC encompasses the states of Washington, Oregon, Idaho, Western Montana, California, Nevada, Wyoming, Utah, Colorado, Arizona, New Mexico, a small portion of Texas, the Canadian provinces of British Columbia and Alberta, and a small portion of Baja Mexico.

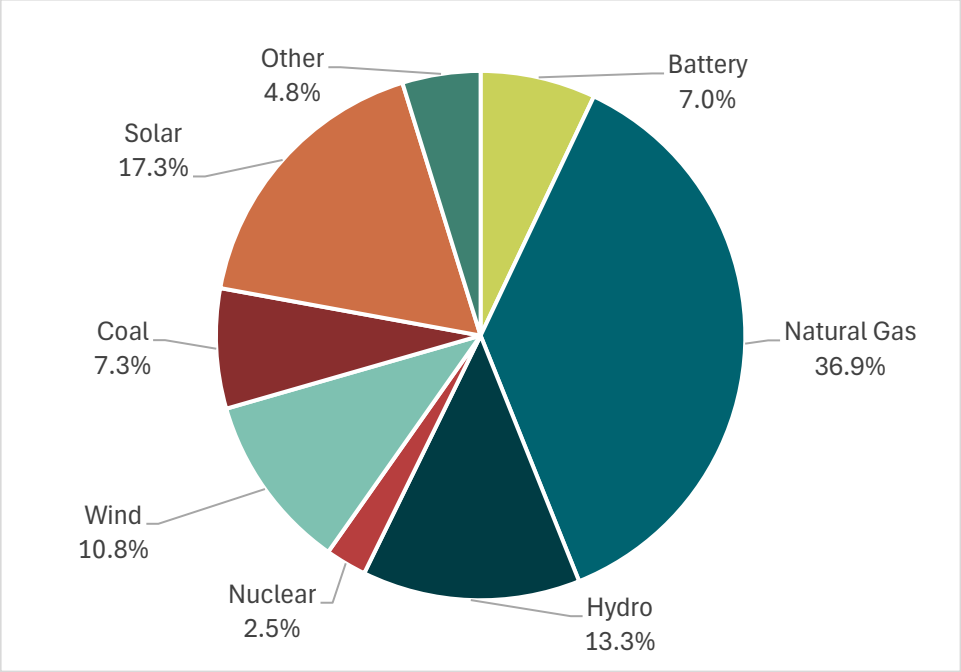
The Council's modeling of the WECC informs market availability. All three primary Council models, Aurora, OptGen/SDDP, and GENESYS, include a load and resource representation of the WECC.[20] As a result, the Council tracks load and resource developments across the WECC.

Description of Existing Fleet by Generating Resource

Comparing the scale of the regional resource mix, shown in Figure B - 3, and that of the WECC, see Figure B - 15, the region has installed about 62,000 MW of nameplate capacity, while the WECC, excluding the region, has about 242,000 MW of installed resource.

[20] More information on these models can be found in Technical Appendix K – Modeling Framework.

Figure B - 15: Installed Nameplate Capacity in the WECC



The mix of the region is particularly distinct within the broader WECC, with over half of our energy coming from hydro while the WECC has a more varied mix. Those discrepancies can largely be explained by geographical access and sizes of load served, but it is notable that as the Pacific Northwest's load grows and clean policies drive resource builds across the west, those mixes may start to look more similar.

Proposed Retirements and Conversions

Similarly to the region, states in the wider WECC are retiring their coal fleets for similar reasons, including rising fuel cost, aging efficiency, and rising policy enforced concerns about carbon emissions. These planned changes to the existing system are captured in the model so that the final power plan is responsive to and plans for these large changes in existing generation. Concerns about ballooning load growth has prompted many previously announced coal retirements to instead convert the plant to burning natural gas rather than shuttering entirely.

Table B - 4: WECC-Wide Coal Retirements and Conversion by Plant

State	Plant Name	Nameplate Capacity (MW)	Planned Retirement
AZ	Apache Station	*204*	Conversion by 2027
AZ	Cholla	425.9	2025
AZ	Coronado	821.8	2032
AZ	Springerville	1765.8	2027/2032
CA	Argus Cogen Plant	62.5	

State	Plant Name	Nameplate Capacity (MW)	Planned Retirement
CO	Comanche (CO)	1252.8	2022/2025/2030
CO	Craig (CO)	1427.6	2025/2028
CO	Hayden	465.4	2027/2028
CO	Pawnee	*552.3*	Conversion by 2026
CO	Rawhide	293.6	2029
CO	Ray D Nixon	207	2029
MT	Colstrip	1647.4	
MT	Colstrip Energy LP	46.1	
MT	Hardin Generator Project	115.7	
MT	W. Sugar Cooperative - Billings	1.5	
NM	Four Corners	1636.2	2031
NV	North Valmy	*567*	Conversion by 2026
NV	TS Power Plant	242	
UT	Bonanza	499.5	
UT	Hunter	1472.2	2042
UT	Huntington	1015.5	2036
UT	Intermountain Power Project	*1640*	Converted in 2025
UT	Sunnyside Cogen Associates	58.1	
WA	Transalta Centralia Generation	729.9	Conversion expected late 2028
WY	Dave Johnston	*816.7*	Conversion by 2029
WY	Dry Fork Station	483.7	
WY	General Chemical	30	
WY	Genesis Alkali	41	
WY	Jim Bridger 3&4	1216	
WY	Jim Bridger 1&2	1225	Converted in 2024
WY	Laramie River Station	1863	
WY	Naughton	*380.8*	Conversion in 2026
WY	Neil Simpson II	90	
WY	Wygen 1-3	90, 95, 116	
WY	Wyodak	362.1	2039

Table B - 5: WECC-Wide Coal Retirements

	Nameplate Capacity (MW)
Retired Coal	10,660
Operating Coal	21,300
Coal Leaving System	
Coal-to-Gas Conversion (incl. planned)	*4,160*
Planned Retirement by 2030	*5,685*
Planned Retirement post-2030	*6,812*
Total Coal Leaving System	**16,658**

Greenhouse Gas Emissions from Generation

Regional and state policies are shaped by the goal of reducing emissions and countering climate change by deploying clean energy resources. In describing the existing system it is important to understand historical emissions, changes in the generation stack and dispatch, and trends (both past and present).

The electricity sector is one of the primary sources of greenhouse gas emissions globally. An analysis from the Energy Information Agency (EIA) has shown that amongst energy-related sectors at the national level, the electricity sector has been the greatest emitter of carbon dioxide (CO_2) until 2016 when the transportation sector surpassed it.[21]

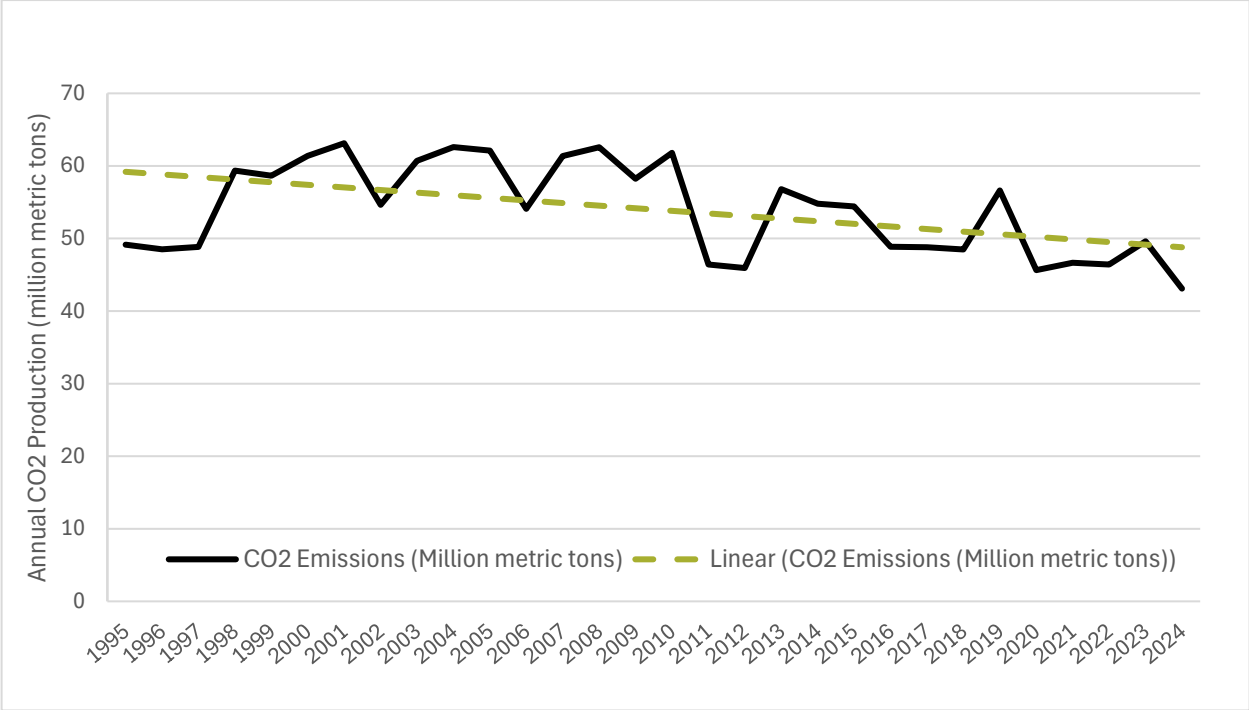
This section will describe historical regional emissions as well as how ongoing and future emissions are captured in the modeling. For a more comprehensive look at the environmental effects of the power system and how those are considered in the power plan, see Technical Appendix C: Methodology for Quantifiable Environmental Costs and Benefits.

Historical Carbon Dioxide Emissions

In the Pacific Northwest, the amount of annual carbon emitted from the generation of electricity is directly related to hydro conditions. Because the region's power supply is dominated by hydropower, other resources – primarily fossil fuels – are dispatched around the hydro supply and the region's carbon emissions often bounce around from year to year accordingly as seen in Figure B - 16. The recent move away from coal has prompted a downward trend on the region's CO_2 emissions as that hydro backup is getting cleaner.

[21] https://www.eia.gov/environment/emissions/carbon/pdf/2024_emissions_report_final.pdf.

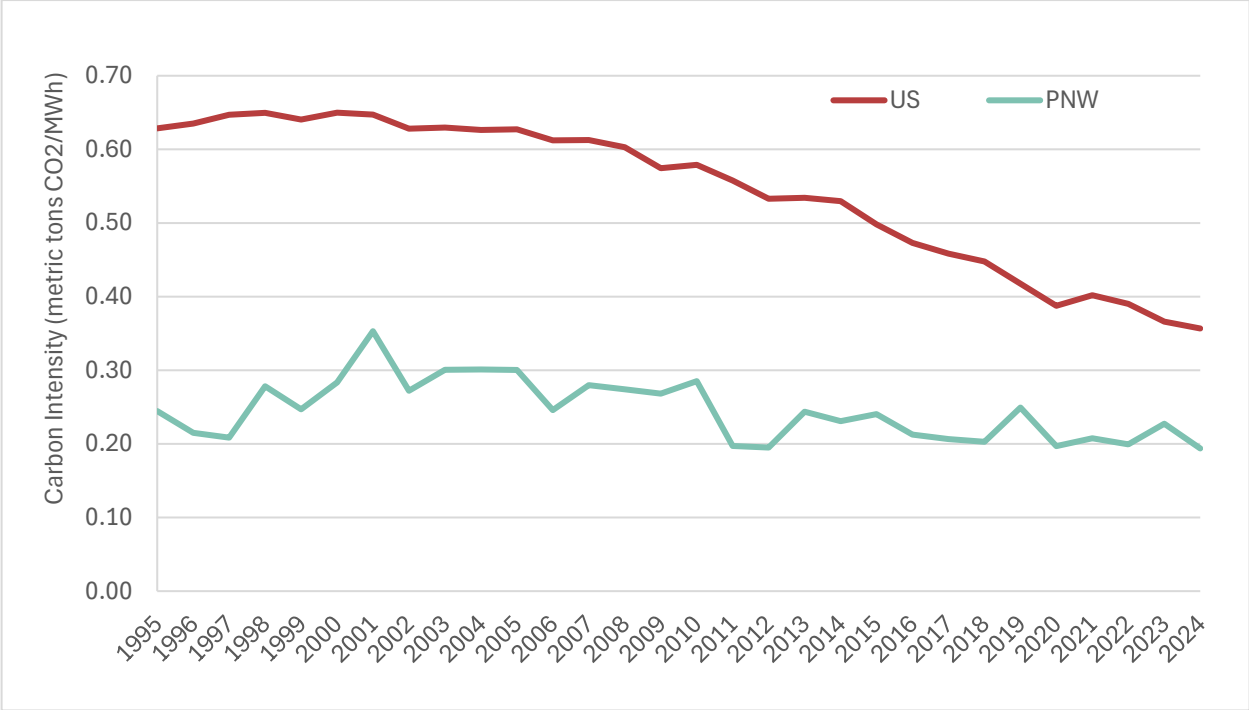
Figure B - 16: Annual CO_2 Emissions from Electricity Generation in the Region



United States Generation and CO_2 Emissions

The region's robust hydro resource has kept its electricity emissions relatively low in comparison to the rest of the nation, as well as its concerted investment in energy efficiency. However, United States carbon emissions from the electricity sector have been declining steadily since the mid-2000's. Due to hydropower's smaller role in the nation's resource portfolio, there is not the same variability from year to year as seen in the Pacific Northwest. Rather, declining emissions can be directly attributed to the change in fossil fuel dispatch and greater reliance on the less carbon intensive natural gas resources over coal. Carbon intensity is the amount of carbon emitted per unit of energy generated and serves as an illustrative lens by which to compare the United States' emissions to the Region's. In table we can see that the Pacific Northwest's energy mix has been relatively clean but varies depending on the Hydro system supplying more or less of the region's energy in a given year. The United States on the other hand has been steadily decreasing in CO_2 intensity as higher emitters are replaced and their energy mix becomes more renewable.

Figure B - 17: CO_2 Intensity of the Region's Electricity Mix versus the United States'



Emissions Rates

Different emissions rates associated with the dispatch of emitting resources. Each fuel type has a particular emission rate which is then applied to a particular plant based on its fuel use and heat rate. These emissions by fuel type are detailed in Table B - 6 below. The Council utilizes the CO_2e emissions rate, to account for the global warming potential of CO_2 (carbon dioxide), CH_4 (methane), and N_2O (nitrous oxide).

For modeling in the Ninth Plan, the Council's models are agnostic to these emissions, in that they will not retire a plant or temper its dispatch to reduce emissions to meet any of the clean targets. However, the economics of a high emitting resource, as clean policies become more stringent and carbon prices in applicable jurisdictions rise, will affect the further dispatch of that resource. In that way, these emissions rates affect the ongoing costs of the existing system and those resulting costs have bearing how the system is used.

Table B - 6: CO2e Emissions by Fuel Type[22]

Fuel Type	Time Horizon	Total CO2e (lbs CO2e/MMBtu)
Natural Gas	GWP[23] 100 yrs	117
	GWP 20 yrs	117
Coal	GWP 100 yrs	213
	GWP 20 yrs	216

Existing Policies

Treatment of Policies in Ninth Power Plan

The energy policy landscape lays the groundwork upon which the Council understand the future of resource development in the region and country. What those policies are and how they are represented in the Council's planning is an important early step in the power plan development process.

In developing its regional power plan, the Council must consider and incorporate environmental effects associated with the power system into its analysis and development of a resource strategy. As identified in the Northwest Power Act, the Council is to encourage, in a manner consistent with applicable environmental laws and through the unique opportunity provided by the Federal Columbia River Power System, conservation and efficiency in the use of electric power and the development of renewable resources to assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply.[24] With a finer point, the Act requires that the Council set forth a scheme for implementing conservation measures and developing resources with due consideration by the Council for, among other things, environmental quality, compatibility with the existing regional power system, and protection, mitigation, and enhancement of fish and wildlife.[25] It additionally requires the Council include as an element of the power plan a methodology for determining quantifiable environmental costs and benefits of new resources,[26] and the Council's planning assumes all

[22] Emissions by fuel type source: https://www.epa.gov/system/files/documents/2025-01/ghg-emission-factors-hub-2025.pdf. Global warming potential source: https://www.edf.org/sites/default/files/content/emission_equivalency_tool_documentation_methodology_23062022.pdf.

[23] Global warming potential (GWP) measures the radiative efficiency, or ability to absorb energy, of the greenhouse gas over its lifetime. It is used to normalize GHGs to CO_2e so that they can be compared by potency, or how much energy the gas absorbs over x number of years.

[24] Northwest Power Act, §2(2), 94 Stat. 2697.

[25] Northwest Power Act, §4(e)(2), 94 Stat. 2706.

[26] Northwest Power Act, §4(e)(3)(C), 94 Stat. 2706.

generating and conservation resources will meet existing federal, state, tribal, and local environmental regulations. More detail about what is included in that methodology and how it is developed can be found in Technical Appendix C - Methodology for Quantifiable Environmental Costs and Benefits.

Policy Levels

The Council represents multiple regulatory levels of policy and the ways they interact and potentially impact future loads, resource costs, and other power planning dynamics. The policies described below are sorted into federal, regional, and WECC-wide and then additionally delineated into state, local, and utility policies.

The below-described policies are further grouped within a simple framework intended to broadly designate how the policy is captured in modeling, whether in terms of a load impact, resource options, impact, or resource cost impact. Policies that impact resource options are those that affect what resources are available to the model and how/if they might be selected. For example, renewable portfolio standards would fall into this category because it impacts how much renewable resource the model required to select. Policies with resource cost impacts describe policies that influence the cost of a resource either through cost of compliance with an environmental regulation or via an incentive. Finaly, policies categorized as load impacting refer to those that affect the electric load by, for example, promoting electrification or incentivizing energy efficiency.

Federal

A primary cost quantified in the environmental methodology are those from assumed compliance with existing regulations, which are incorporated into the total system cost of a new resource. To inform that analysis, Table B - 7 provides a high-level overview of the primary federal statutes that arise when considering the environmental impacts of resources and the regulation thereof.

This section also provides high-level status overview of several recent federal regulations, which, at the moment present a regulatory backdrop in flux given the number of environmental regulations proposed and issued during the last presidential Administration, the legal challenges to those regulations, and the early executive orders and agenda of the new administration regarding the environment and climate change – all of which spanned the development of this power plan.

Notably Table B - 7: Federal Policy SummaryTable B - 7 describes the Inflation Reduction Act (IRA) and the Bipartisan Infrastructure Law (BIL), both of which have been pared back by the current Administration's One Big Beautiful Bill Act (OBBBA). Capturing existing policies is an early step in the Plan process, and during the initial analysis both bills were still fully in-effect and a significant legislative change since the previous plan. At the time of this writing, that is no longer the case. For the most part, the OBBBA rolled back federal money available for clean energy grants and energy efficiency programs and incentives. Most of those changes, while impactful to the energy landscape as a whole, are not modeled explicitly and therefore will not affect our analysis directly. More details about energy efficiency funding can be found in Technical Appendix H – Conservation Methodology and Potential. The most impactful changes were to the clean energy tax credits, narrowing the

resources they apply to, notably excluding wind and solar resources. The OBBBA also repealed the IRA's changes to the Clean Air Act § 111(b) and (d) which set source performance standards for carbon emissions from new and existing sources, reverting them back to the previous standard of best available technology.

Policy can be a locus of high uncertainty in planning. The four-year cadence of potential administration turnover means that policy can be volatile and highly reactive to political winds. The risk of this uncertainty is explored in scenario analysis, the details of which are discussed in Technical Appendix N – Scenario Modeling and Results.

Table B - 7: Federal Policy Summary

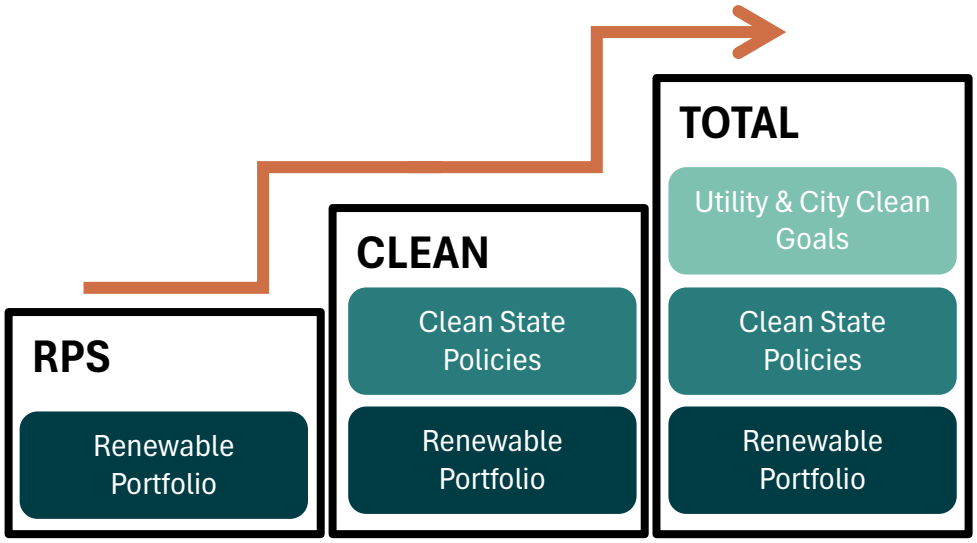
Name	Role in Modeling	Summary
One Big Beautiful Bill Act (OBBBA)	Resource Cost (minor Load & Resource Choice Impacts)	In relation to the Council's work, this Bill operates as primarily a dampener on the impacts of the IRA. Its main impacts are: • Removing tax credits for wind and solar technologies, energy efficiency programs, and electric vehicles. • Rolling back the new carbon emission performance standards for new and existing sources in the Clean Air Act.
Inflation Reduction Act (IRA)	Resource Cost Load	A broad policy that is most impactful to Council's work in the implementation of a technology neutral 30% investment tax credit and/or a 2.75 cent production tax credit The technology these credits apply to was altered by the passage of the OBBBA These tax credits remain in the modeling as the basis for the evolving federal policy landscape sensitivity
Bipartisan Infrastructure Law (BIL)	NA	Another wide-ranging policy, that mostly focuses on grants, pilot programs, & demonstration projects. A few notable pieces though they won't be explicitly modeled: Power marketing administration (BPA) transmission borrowing authority expanded, incentives for maintaining and enhancing hydroelectricity
Clean Air Act	Resource Cost Resource Options	The primary purpose of the Clean Air Act is to protect and enhance air quality to promote the public health and welfare of the nation's population. Most relevant, and new since the last plan are: • New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d): • New baseload stationary combustion turbines must have 90% CCS by 2032. Existing coal fired plants planning on operating after 2039 must be equipped with 90% CCS by 2032

Name	Role in Modeling	Summary
Endangered Species Act	Resource Costs (cost of compliance)	Established a framework to conserve and protect endangered and threatened species and their critical habitats
National Environmental Policy Act		Procedural statute that requires federal agencies to consider the environmental impacts of their proposed actions and provide for public involvement in the federal decision-making process
Clean Water Act		Principal federal statute regulating water pollution and protecting the nation's "navigable waters."
Public Utilities Regulatory Policies Act	Resource Options (mostly NA)	PURPA established a class of non-utility generating facilities that, if meeting certain requirements, are permitted to sell the output of their power plants to utilities at the price the utilities would have to pay to develop their own resources. Qualifying facilities are primarily small power production facilities and cogeneration facilities
Codes & Standards	Load	Regulations that establish minimum requirements for energy performance in buildings, appliances, and other products, aiming to reduce energy consumption, essentially defining a level of energy efficiency that must be achieved

In-Region

In past plans, only federal and state level mandates were represented as parameters in the model, but the 2021 Power Plan made the methodological change to incorporate clean policies more broadly. The new methodology included all clean policies and goals at the state, utility, and community level framed as a portion of sales obligated to meet a percentage clean target. By aggregating the different jurisdictions' clean policies based on the percentage of sales they represent, on either the regional or WECC level, the Council was able to roll those up into a total regional or WECC clean policy goal. This roll up is necessary for modeling, in that it is more efficient that inputting each policy individually. It also represents all applicable clean policies and their impacts on the energy policy landscape of the region in a way that previous methodologies that excluded the utility, city and municipality level policy goals, did not. This process, and how it is incorporated into the modeling, is described in more specific detail by state below.

Figure B - 18: Aggregating Clean Energy Policies and Goals



Washington

Washington's Clean Energy Transformation Act (CETA) is the only policy in the region to set a statewide goal of 100% clean energy by 2045. Washington takes a ramped approach, eliminating coal-fired generation serving Washington customers by 2025, making all electric utilities greenhouse gas neutral by 2030, and requiring 100% of electric utility power to come from renewable or zero-carbon resources by 2045. CETA applies to 100% of Washington state sales. These goals are paired with the Climate Commitment Act (CCA) which was established in 2021. It sets an economy-wide cap on greenhouse gas emissions and established a cap-and-invest program with emissions allowances that decrease over time in alignment with meeting the state's emissions reduction commitments. This creates a price for carbon that is accounted for in the Council's modeling.

Oregon

Oregon's clean energy targets apply primarily to its largest utilities and are borne of a few different policies. The most recent, and most impactful, is HB2021, the Clean Energy Targets Bill, which requires Porland General Electric (PGE), PacifiCorp (PAC), and Electricity Service Providers to reduce greenhouse gas emissions from the electricity they sell to retail consumers in Oregon by 80% below baseline emissions levels by 2030, 90% below baseline by 2035 and 100% by 2040. The state also has a longstanding renewable portfolio standard, which for investor-owned utilities is quickly subsumed by HB2021, but remains for consumer owned utilities to whom HB2021 does not apply. PGE, PAC, and smaller utilities have had personal clean utility goals, that have similarly been surpassed by larger state goals. PGE and PAC make up about 60% of state sales, while qualified Electricity Service Suppliers account for about 5%, meaning that Oregon's most stringent clean goals, those set by HB2021, apply to about 65% of total state sales.

Idaho

Idaho has no statewide clean energy goals, but that does not mean there are no clean goals to plan for in Idaho. The state's two largest utilities have clean energy goals as well as the state's largest city:

- Boise 100% citywide clean by 2035: ~20% state sales
- Idaho Power 100% clean energy by 2045: ~60% state sales
- Avista 100% clean electricity goal by 2045 and carbon neutral by 2028: ~15% state sales

Accounting for overlap between the City of Boise and the two utilities, the percentage of state sales under a clean policy goal is about 75% by 2045.

Montana

Montana also has no statewide clean goals – having repealed their RPS in 2021. But, similarly to Idaho, there are key energy sector actors that have set their own goals:

- Bozeman, Missoula, and Helena have 100% clean electricity goals by 2030: ~20% of state sales
- NorthWestern Energy has a Net Zero Vision of 100% clean electricity by 2050: ~38% of state sales excluding three clean cities

The portion of Montana sales committed to meeting clean goals is about 58% by 2050.

Cumulative/Aggregate Regional Clean Energy Goals

In aggregating the region-wide clean target, each state represents the below assigned portion of regional sales, and therefore their policies apply to that percentage of the total region. That cumulative clean policy target is then set as a parameter for the region in the model.

Table B - 8: In-Region State Sales

State	State Sales (MWh)	Portion of total Regional Sales[27]
Washington	88,072,642	49%
Oregon	56,091,824	31%
Montana	11,316,503	6%
Idaho	25,124,385	14%

[27] Based on a three-year average (2022-2024) of state sales as reported by Form EIA-861: https://www.eia.gov/electricity/data/eia861.

To translate Table B - 8, any clean goals set by Washington will apply to 49% of the total region's sales, Oregon's goals will apply to 31%, and Montana and Idaho will apply to 6% and 14% respectively.

Table B - 9: In-Region Clean Policies as Percentage of Regional Sales[28]

	2027	2030	2035	2040	2045
PNW RPS	13%	15%	16%	17%	17%
PNW RPS + Clean State Policy Targets	13%	66%	68%	72%	76%
WECC RPS + Clean State & Jurisdiction Targets	16%	70%	74%	83%	88 %

Table B - 9 shows in 2027, the beginning of the power plan analysis, 13% of regional sales are obligated to be clean by regional RPS policies. Both Oregon and Washington have state-wide clean policies that set higher clean targets by 2030, requiring 66% of the region's sales to be clean by that year. While Idaho and Montana have no clean policies at the state level, the clean city and utility targets set within the state are folded into the final row of the above table, with a cumulative regional clean target of 83% clean sales by 2045. The progression of figures, from the much lower RPS target in Figure B - 19 to the total target incorporating all clean policies at all jurisdictional levels in Figure B - 21, shows how the individual state goals compare to each other, and how they coalesce into a single regional goal.

[28] The final target set by both Oregon HB2021 and Washington CETA, obligates 100% of load be clean, which is a higher requirement than 100% clean sales due to line losses. That difference has been incorporated into these aggregate percentages.

Figure B - 19: In-Region Renewable Portfolio Standards

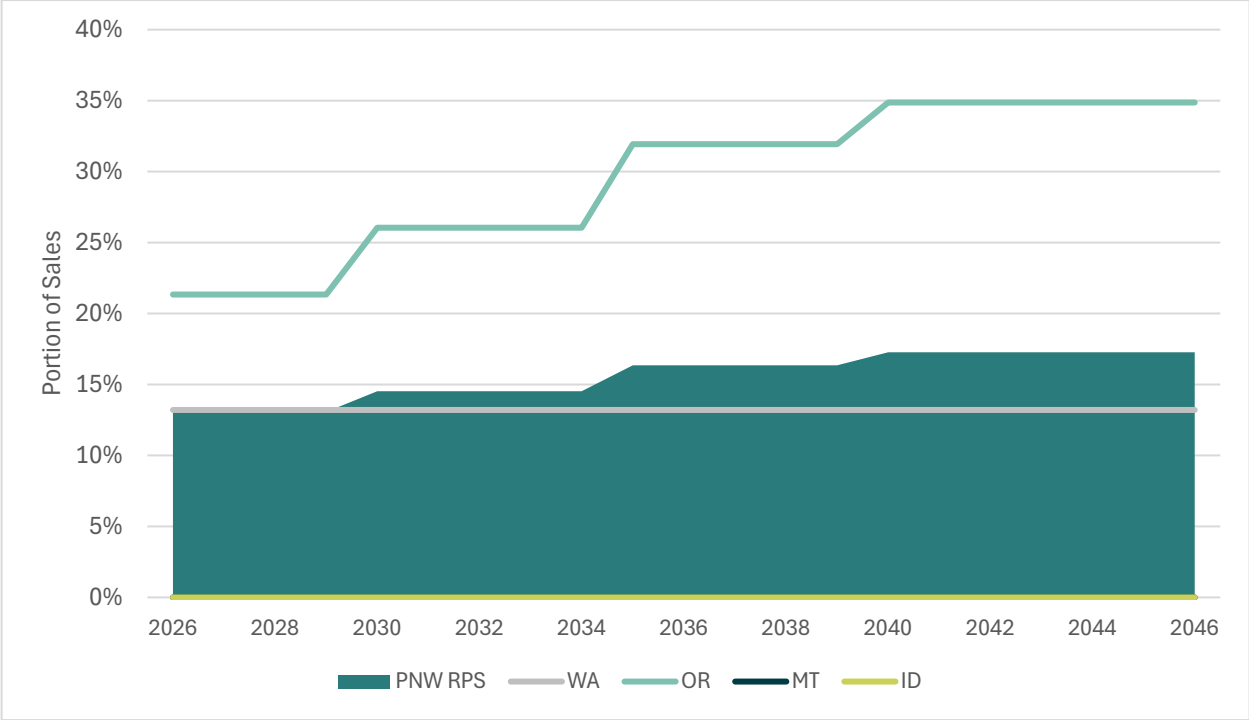
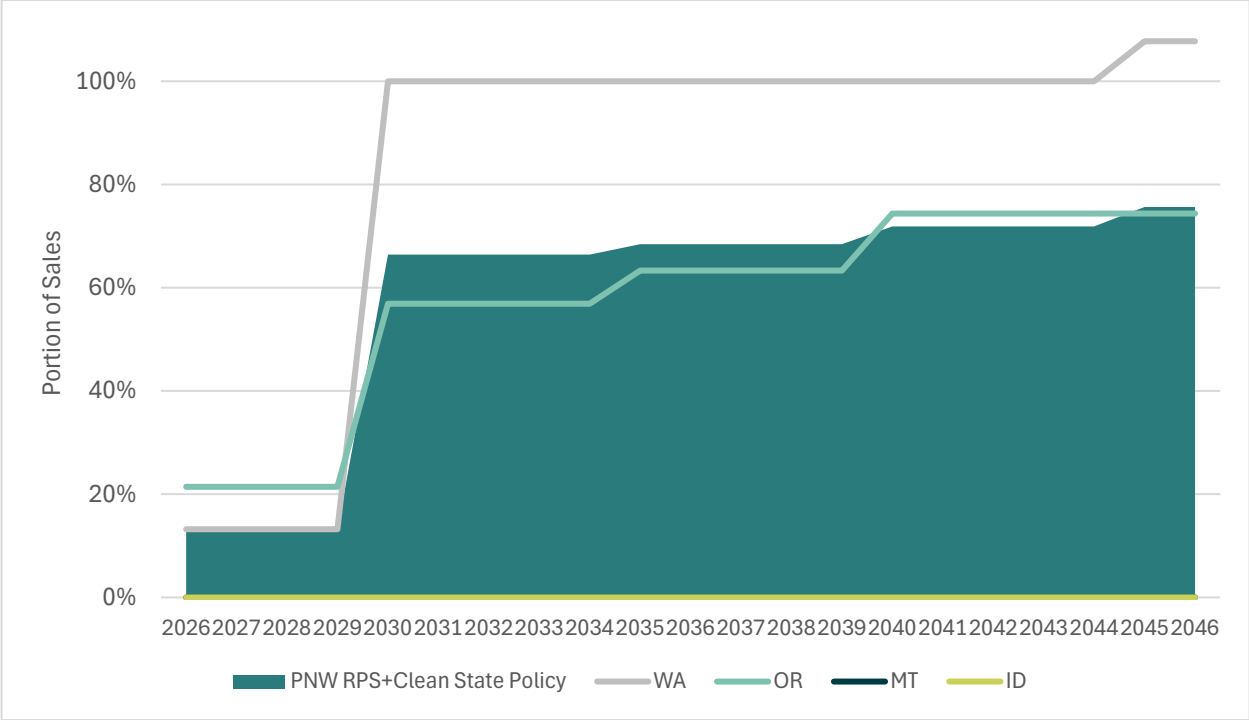
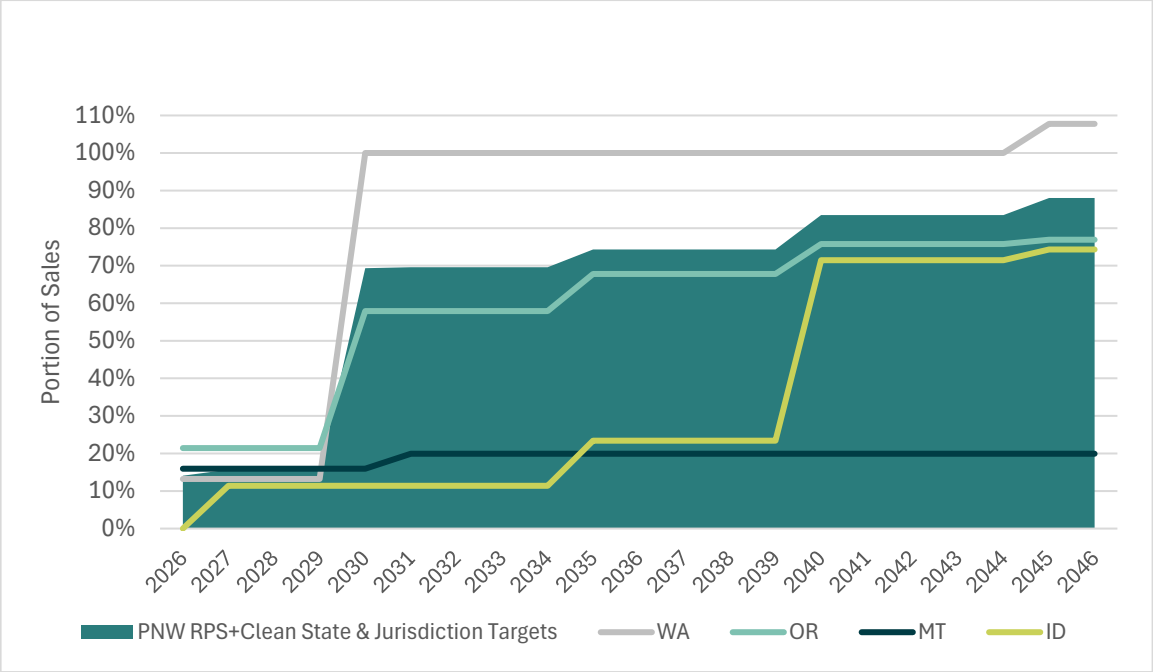


Figure B - 20: In-Region RPS & Clean State Policies[29]



[29] As described in the previous footnote WA and OR policies apply to 100% of load which is a larger than sales (pre-line losses). In application during modeling, these percentages will be applied to future load and will account for line loss, but when applied to sales, like in these charts, the portion of sales is higher than 100%.

Figure B - 21: In-Region RPS, Clean State Policies, & Jurisdictional Targets[30]



The data and calculations behind the figures above can be found here: https://nwcouncil.box.com/s/rml2931at2xtxfngtomj6w6xlidyo6bu.

Table B - 10 summarizes the in-region policies relevant to the Ninth Power Plan assumptions.

Table B - 10: Washington Energy Policy Summary

Name	Role in Modeling	Summary
Washington		
Clean Energy Transformation Act (CETA)	Resource Options	Requires utilities: • eliminate coal-fired resources from WA rates by 2025 • be carbon neutral by 2030 • be 100% clean by 2045 • use the social cost of carbon in their resource planning

[30] "Jurisdictional" refers to local city and utility goal, these are not necessarily binding, but the intentions of these sub-state jurisdictions are still important to account for when planning.

Name	Role in Modeling	Summary
Climate Commitment Act (CCA)	Load (electrification) Resource Cost (added cost to emitting resources)	Cap & invest program, utilities subject to CETA are allocated allowances under CCA in alignment with their carbon reduction goals set by CETA
Advance Clean Cars II Rulemaking on Low and Zero Emission Vehicles	Load	Requires 100% of new light duty vehicles to be ZEV or PHEV by 2035 Adopted CA clean truck rules
Clean Fuel Standard	Load	Requires suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034
Clean Building Performance Standard	Load	Covered buildings must comply by meeting an energy performance metric (EUI target)
Codes & Standards	Load	Building code and appliance standards above and beyond the federal standards
Renewable Portfolio Standard	Resource Options	15% by 2020
Healthy Environment for All (HEAL) Act	NA (could consider in narrative)	Requires Ecology and the state departments of Agriculture, Commerce, Health, Natural Resources, Transportation, and the Puget Sound Partnership to identify and address environmental health disparities in overburdened communities and for vulnerable populations.
Oregon		
HB2021	Resource Options	Directs utilities to reduce emissions levels below 2010-2012 baseline levels by: • 80% by 2030 • 90% by 2035 • 100% by 2040 Also expanded the capacity standard for Small Scale Renewables from 8% to 10%
Climate Protection Program 2024	Load (electrification)	Sets an enforceable declining cap on GHG emissions from fossil fuels used throughout Oregon, including diesel, gasoline, and natural gas. Designed to reduce these emissions by 50% by 2035 and 90% by 2050

Name	Role in Modeling	Summary
		Regulated entities include natural gas utilities, fuel suppliers, energy intensive trade-exposed industry sources, and direct natural gas sources – this policy does not apply directly to the electric sector.
Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles **Advanced Clean Truck Rules**	Load	100% of new light duty vehicles to be ZEVs or PHEVs by 2035 Increasing sales targets for zero emission MHDV starting in 2025
SB1547 Community Solar	Resource Options	Requires the Oregon Public Utility Commission to establish a program for the procurement of electricity from community solar projects.
Energy Performance Standard for commercial buildings	Load	Based on 2024 ASHRAE Standard 100, with OR specific amendments, sets EUI targets for different building commercial types
Codes & Standards	Load	Building code and appliance standards above and beyond the federal standards
Renewable Portfolio Standard	Resource Options	Directs utilities' generation be: • 35% renewable by 2030 • 45% by 2035 • 50% by 2040 *With lower requirements for smaller utilities.
Montana		
Missoula- 100% Clean Electricity Initiative	Resource Options	100% clean electricity by 2030 for the Missoula urban area
Bozeman-2020 Climate Plan	Resource Options	100% net clean by 2030 Carbon neutral by 2050
Helena-100% Clean Electricity Goal (city council resol.20592)	Resource Options	100% clean electricity by 2030, interim goal of 80% by 2025

Name	Role in Modeling	Summary
NorthWestern Energy "Net Zero Vision"	Resource Options	Net zero emissions by 2050
Idaho		
Boise's Energy Future	Resource Options	100% citywide clean electricity by 2035
Idaho Power	Resource Options	100% clean energy by 2045
Avista	Resource Options	100% clean electricity by 2045 and carbon neutral by 2028

WECC

The Council produces a *regional* power plan. However, the region does not exist in a vacuum, and the resource type and the amount of energy available from the broader west impacts in-region behavior and decision making. The Council's modeling of the WECC informs market availability of energy in the region. As a result, it is important to capture the relevant polices that impact resource development and dispatch in the WECC, which will affect market fundamentals within the region.

Policies that are especially impactful in the region – because they both set steep clean goals and are from large jurisdictions therefore placing a large percentage of the WECC under a high clean energy goal – are the Californian and Canadian carbon prices. When paired with Washinton's carbon tax, set by the CCA, a large portion of the West's emitting resources fall under a high, and rising, price. This steeply disincentivizes the use of the existing thermal fleet or the building of new thermal resources – because it becomes increasingly difficult to find a place to sink that energy that doesn't have to pay that premium.

Table B - 11 and Table B - 12 below summarize the existing policies in the WECC that inform the Council's Ninth Power Plan analysis.

Table B - 11: US WECC-Wide Policy Summary

Name	Summary
California	
Assembly Bill 1279 (2022)	Reduce economy wide GHG emissions 85% below 1990 levels by 2045
Advanced Clean Cars II rule	By 2035 all new passenger vehicles sold in CA will be ZEVs
100% Clean Energy Act (SB 100) +Clean Energy, Jobs & Affordability Act	100% of CA electricity to come from clean sources by 2045 Interim targets:

Name	Summary
	• 90% of all retail sales of electricity to CA end-use customers clean by 2035 • 95% by 2040 • 100% by 2045 • 100% of electricity procured to serve all state agencies clean by 2030
Renewable Portfolio Standard	60% renewable by 2030
Utah	
Community Renewable Energy Act (HB411)	Opt-out program with a goal of being 100% net renewable by 2030 (19 cities in UT are currently participating and have adopted 100% renewable goals by or before ~2030)
Renewable Portfolio Standard	20% renewable by 2025
Wyoming	
Reliable and Dispatchable Low-Carbon Energy Standard Statute (HB 200)	Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2033 if technically and economically feasible (at least 20%)
Nevada	
Renewable Portfolio Standard	50% renewable by 2030
SB358	100% carbon free energy production by 2050
Arizona	
Renewable Portfolio Standard	15% renewable by 2025 (30% of that from distributed resources)
Arizona Public Service	100% carbon neutral by 2050 65% clean (45% renewable) by 2030
Tucson Electric Power Company	Net zero direct GHG emissions by 2050, 80% reduction in CO2 by 2035
Salt River Project	Goal is to reduce the amount of CO_2 emitted by generation (per MWh) by 82% from 2005 levels by 2035 (~284 lbs./MWh) and reach net zero carbon emissions by 2050.
Colorado	
Renewable Portfolio Standard	IOUs: 30% renewable by 2020 Munis: 10% by 2020 Coops: 20% by 2020
Roadmap to 100% Renewable Energy	Governor goal/commitment: 100% renewable energy by 2040

Name	Summary
HB-1261	Sets economy-wide targets for reducing greenhouse gas pollution, with goals of 26% reduction by 2025 below 2005 levels, 50% reduction by 2030 and 90% reduction by 2050
H21-264	GHG reduction targets for gas utilities: 4% reduction below 2015 GHG emission levels by 2025 and 22% by 2030.
XCEL Energy	Reduce CO2 emissions 80% lower by 2030 100% carbon-free electricity by 2050
Platte River Power Authority	100% noncarbon energy mix by 2030
Poudre Valley REA	80% carbon-free energy by 2030
Holy Cross Energy	100% clean energy by 2030
Denver Renewable Energy Action Plan	100% renewable electricity community wide by 2030
New Mexico	
Renewable Portfolio Standard (NM Energy Transition Act)	IOUs: 50% by 2030 100% carbon-free by 2045 Rural Co-ops: 10% by 2020, 40% by 2025, 50% by 2030, 100% carbon-free by 2050
Xcel Energy	100% carbon-free by 2050
Public Service of NM	100 emissions free by 2040

Table B - 12: International WECC-Wide Policy Summary

Name	Summary
Canada	
British Columbia: Clean electricity target	100% by 2030
Alberta: Clean electricity target	30% by 2030
National: Carbon Tax	Canada-wide

Cumulative/Aggregate WECC Clean Energy Goals

For the purposes of aggregating WECC policies into a WECC-wide clean target, each state represents the below assigned portion of WECC sales, and therefore their policies apply to that percentage of the total WECC. The aggregate clean policy target for the entire WECC then is set as a parameter in modeling. The logic of the tables and charts below follows that laid out on the regional scale above. For example, California makes up 28% of WECC-wide sales and so their policies apply to 28% of the total WECC. Additionally, in this look, the region is just a portion of the total WECC with Washington, Oregon, Montana and Idaho making up 14%, 9%, 2%, and 4% of the broader WECC respectively.

Table B - 13: WECC-Wide State Sales

	State	Portion of total WECC Sales
Region	Washington	14%
	Oregon	9%
	Montana	2%
	Idaho	4%
WECC	Arizona	14%
	California	28%
	Colorado	9%
	New Mexico	5%
	Nevada	6%
	Utah	5%
	Wyoming	3%

Table B - 14: Clean Policies as a Percentage of WECC Sales

	2027	2030	2035	2040	2045
WECC RPS	28%	32%	33%	34%	35%
WECC RPS + Clean State Policy Targets	28%	51%	60%	63%	67%
WECC RPS + Clean State & Jurisdiction Targets	29%	55%	66%	71%	74%

The data and calculations behind the figures above can be found here on the Council's Ninth Power Plan webpage.[31]

[31] https://nwcouncil.box.com/s/rml2931at2xtxfngtomj6w6xlidyo6bu.

Figure B - 22: WECC-Wide Renewable Portfolio Standards

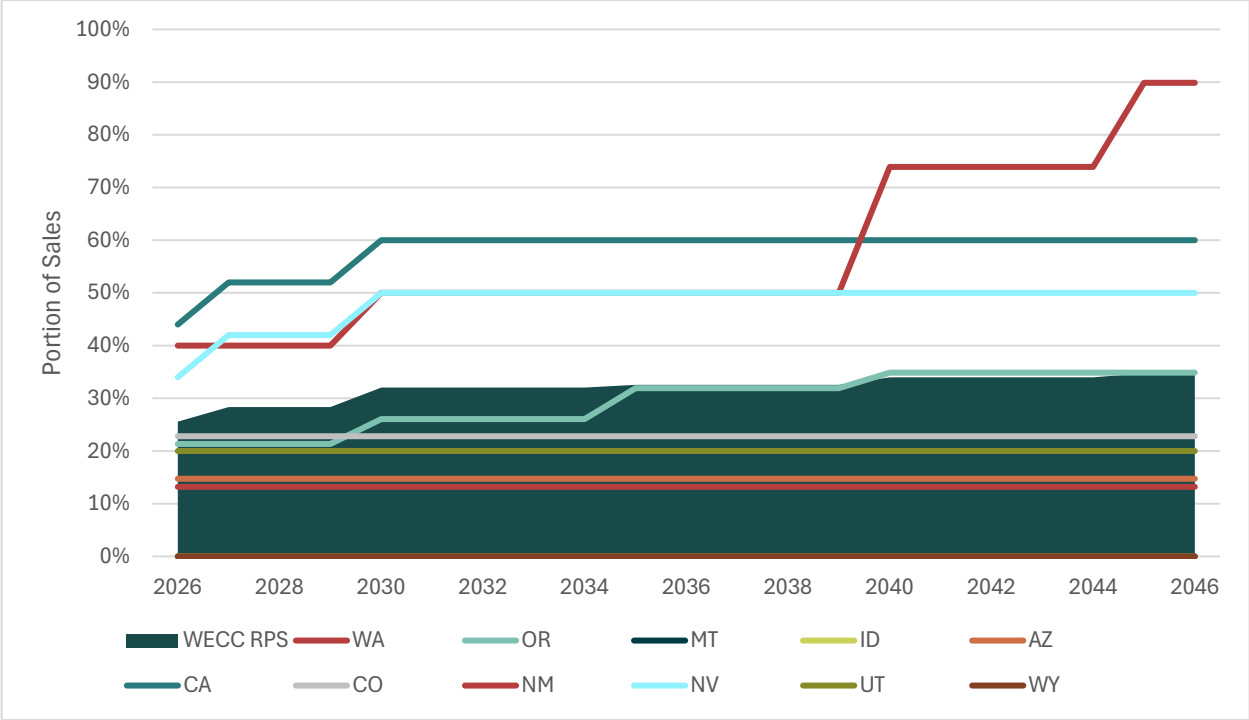


Figure B - 23: RPS & Clean State Policies

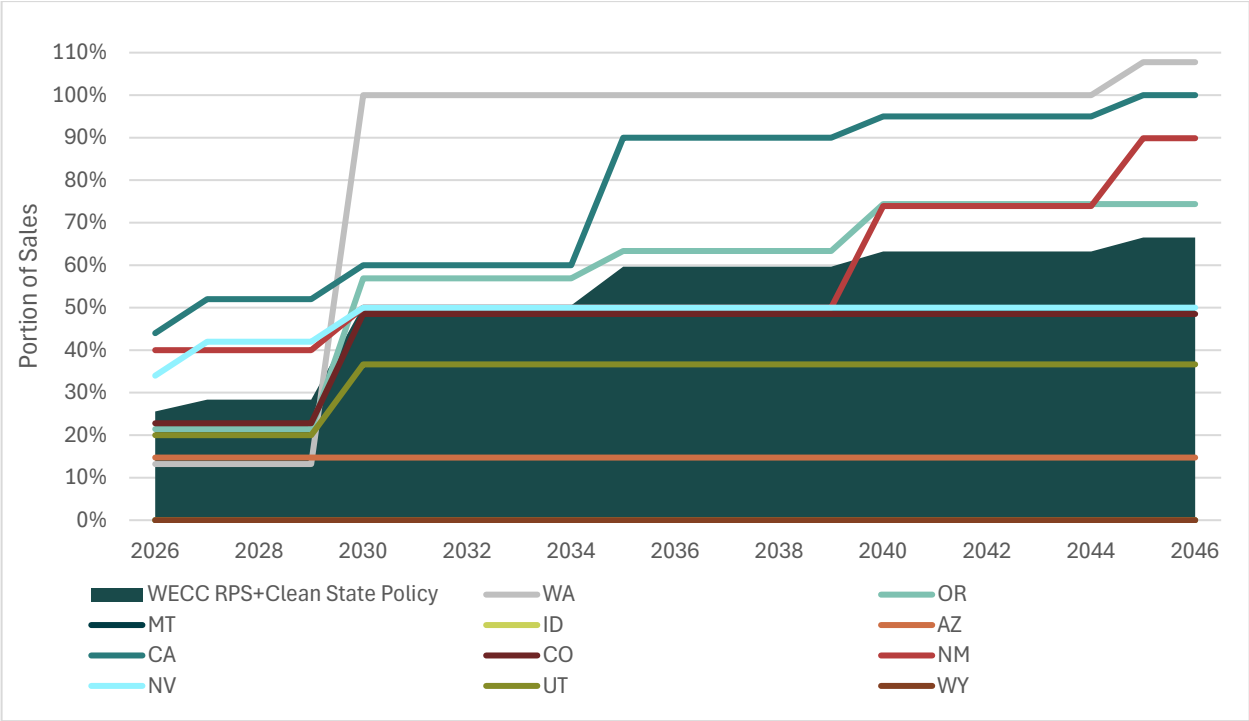


Figure B - 24: RPS, Clean State Policies & Jurisdictional Targets

Planning Under Uncertainty

The work of power planning always takes place under uncertainty. One source of uncertainty is around decisions impacting the existing system into the future. Another is around policies. In an effort understand the breadth of that uncertainty, the plan relies on scenario analysis, designed to test the impact and risk of changing resource availability, resource costs, and transmission availability. Different sensitivities in this analysis will allow for exploration of how changing background conditions might change the solutions produced by the model. More information provided in Technical Appendix N – Scenario Modeling and Results.

Policy in Scenario Testing

During the early scoping process for the Ninth Plan, there was a federal administration change that reversed major energy legislation passed by the previous presidency. These policies are described in Table B - 7 above. Most of the Plan will reflect the current administration's policies, as those are the ones currently enacted as law. However, one scenario that explores changing hydro operations, began analysis before the new law was enacted and therefore reflects previous policies.[32]

[32] This scenario is described in Technical Appendix N – Scenario Modeling and Results.

New Resource and Transmission Risk Scenario

This scenario aims to explore a range of uncertainty and risk related to the region's ability to build new resources and transmission. Each sensitivity within the larger scenario will provide an optimized regional build out given that suite of assumptions across the range of futures. From these different looks collectively, the Council can learn what resources in what amounts are robust across the range of uncertainty as well as what resources or suites of resources might be built to mitigate different risks.

One key sensitivity included in this scenario is the Evolving Federal Policy Landscape sensitivity. Over a 20-year planning horizon, there are always elements of policy uncertainty, and this sensitivity is designed to test how much policy decisions at the Federal level impact resource decisions in the region. This felt especially pertinent given the distinct policy shift between administrations experienced in the early days of this planning cycle.

To test this, the Council designed a sensitivity that brings back policies similar to the tax credits in the IRA and new source emissions requirements under the Clean Air Act. The sensitivity would assume new tax credits for renewables, clean air requirements for new combined cycle combustion turbines, and tax credits for certain energy efficiency measures. These assumptions will be based off of those from the IRA and would come into effect in 2030. The other sensitivities in this scenario will reflect the current policy landscape without clean tax credits or updated emissions requirements.

Technical Appendix C: Methodology for Quantifiable Environmental Costs and Benefits

Contents

Introduction 2
In the Power Act 2
Methodology 3
Cost of Compliance with Existing Environmental Regulations 3
Cost of Compliance with Proposed Regulation 3
Environmental Effects Beyond Regulatory Controls 4
Quantifiable Environmental Benefits 4
Due Consideration of Environmental Effects of Generating Resources 5
Environmental Effects of Hydropower Generation 7
Environmental Effects of Coal Generation 10
Environmental Effects of Nuclear Generation 11
Environmental Effects of Natural Gas-Fired Generation 13
Environmental Effects of Biomass Generation 13
Environmental Effects of Geothermal Generation 14
Environmental Effects of Wind Generation 14
Environmental Effects of Solar PV Generation 16
Environmental Effects of Battery Storage 17
Environmental Effects of Transmission System 17

Introduction

In the development of a new resource strategy for the power plan, the Northwest Power Act requires that the Council compare the incremental system costs of different generating and conservation resources and give priority to those resources which the Council determines to be cost-effective. In estimating the system cost of a particular resource, the Council must include any quantifiable environmental costs and benefits directly attributed to that resource over its effective life.

The Act directs the Council to develop a methodology to determine and apply these quantifiable environmental costs and benefits as part of the overall system cost of a new resource or measure. The methodology's development and implementation are a required element of the power plan.

The Act also requires that in developing the power plan's resource strategy that the Council give "due consideration" to environmental quality and fish and wildlife concerns. These are broader considerations than fit within the methodology for quantifying environmental costs and benefits, which is strictly applied to new resources and their cost-effective comparison, and is described in the later part of this section.

In the Power Act

As laid out in the Northwest Power Act, the Council's power plan is tasked with assuring the Northwest of an adequate, efficient, economical, and reliable power supply. Within that planning the Council must give priority to resources it determines to be cost-effective.[1] Cost-effectiveness is determined by comparing the estimated system costs of different resources;[2] a resources system cost is inclusive of all direct costs of a measure or resource over its effective life. This includes cost of distribution and transmission to the consumer, as well as waste disposal costs, end-of-cycle costs, and fuel costs, and such quantifiable environmental costs and benefits as determined on the basis of a methodology developed by the Council as part of the plan that are directly attributable to such measure or resource.[3]

Within that definition of system cost, the Act explicitly calls out "quantifiable environmental costs and benefits as determined on the basis of a methodology developed by the Council as part of the Plan." Later the Act identifies the development and application of a "methodology for determining [the] quantifiable environmental costs and benefits" of new electric generating and conservation resources as a distinct element of the power plan,[4] clarifying that costs and benefits identified and quantified by the methodology are part of the incremental system cost of a new resource. Notably, the Act does *not*

[1] Northwest Power Act, Section 4(e)(1).
[2] Northwest Power Act, Section 3(4)(A).
[3] Northwest Power Act, Section 3(4)(B).
[4] Northwest Power Act, Section 4(e)(3)(C).

define environment, quantifiable, or directly attributable. The methodology is tasked with defining and justifying the interpretation of these terms and concepts.

Methodology

The Council considers four categories when considering when and how to apply the environmental methodology to determine and quantify the costs and benefits of new resources:

1. Costs of compliance with existing environmental regulations
2. Cost of compliance with proposed environmental regulations
3. Environmental effects beyond regulatory control
4. Quantifiable environmental benefits

Cost of Compliance with Existing Environmental Regulations

The Council's planning assumes all generating resources will meet existing federal, state, tribal, and local environmental regulations. Therefore, the estimated costs of compliance – when quantifiable – are included as part of the total system cost of a new resource. This has been the primary method for capturing and quantifying the environmental costs and benefits in past power plan and will remain so in the Ninth Plan.

- Regulated environmental effects – and the cost of assumed compliance – are varied and are incorporated when applicable across supply and demand side resources. Specifics are discussed in Technical Appendices G through J focuses on new generating and demand side resources and Technical Appendix B is focused on the existing system and policies. Some examples include: Air emissions from generation (SO_x, NO_x, CO_2, methane, mercury) regulated by the Clean Air Act
- Wastewater discharges from generation, regulated by the Clean Water Act
- Solid waste from generation such as toxic/hazardous wastes like coal ash, chemicals in solar panels etc. and nuclear waste
- Regulated environmental effects of fuel productions
- Direct operational effects on fish and wildlife (birds at wind turbines, new hydro effects on fish etc.)
- Cost of environmental compliance in sitting and construction

Cost of Compliance with Proposed Regulation

Quantifying compliance costs for existing regulations is a primary piece of the Council's methodology; however, an additional consideration is compliance with proposed environmental regulations. The Council has typically dealt with proposed regulations on a case-by-case basis depending on the

proposal, the effects the proposal addresses, and the quantitative data available. For the Ninth Power Plan, the Council did not include the cost of compliance for any new proposed regulation, as there were no relevant regulations to consider at the time of power plan analysis.

Environmental Effects Beyond Regulatory Controls

The Council recognizes there are environmental damages or social costs of environmental effects that are not comprehensively regulated and have made efforts to capture what can be quantified. However there remains insufficient data to determine and quantify all environmental effects. These additive effects can be categorized as residual or unregulated.

Residual effects refer to a generating facility's environmental effects beyond the regulated level. For example, coal plant emissions are regulated by strict limits, but they still emit particulates, sulfur dioxide, and hazardous gases up to that limit. Similarly, there are regulatory requirements set on wind turbines intended to reduce bird and bat mortality, but wind farms still kill some birds.

Unregulated effects are those environmental effects not currently regulated but that still cause known impacts to the environment. In past power plans, CO_2, methane, and other greenhouse gas emissions fell within the unregulated category. The regulation of greenhouse gases has evolved in recent years, and the Council has worked to adapt their treatment accordingly. Emissions regulations include a mix of some direct, but fluctuating, regulation under the Clean Air Act, and more ancillary regulations by way of laws and policies that reduce emissions by affecting resource choices, such as state renewable portfolio standards and other clean policy targets.

In the Ninth Plan, the Council has not explicitly included any costs to new resources for these unregulated effects. However, they are still considered in the resource strategy through the implementation of existing policies described above. Through the cost of compliance with these policies and the limits they place on emitting resources, the Council is able to, in part, account for the effect of greenhouse gas emissions at a portfolio level. Greenhouse gas emissions, when not quantifiable, are discussed more broadly as a piece of due consideration of environmental effects. That discussion, can be found in Technical Appendix B – Existing System Parameters and Policies.

Quantifiable Environmental Benefits

The Power Act calls for the quantification of environmental cost, as outlined above, *and* environmental benefits to be included in a new resource cost. This has been a difficult and contentious piece of the environmental methodology throughout the Council's history. Environmental benefits are difficult to capture quantitatively. What, for example, is the dollar value of improved human health outcomes? They are also easily double counted, such as when an environmental benefit comes from reducing an activity with an environmental cost that has already been accounted for. Additionally, benefits are difficult to directly attribute to a specific resource or measure and are hard to apply consistently, which risks skewing our cost comparisons because we have access to some data for some resources but not others.

Water savings can be used to demonstrate the way the Council has contended with incorporating the environmental benefit of reducing an existing activity that has an environmental cost into the costs of a new resource. For example, installation of an efficient washing machine not only saves energy, but also reduces the amount of water used to wash clothes, which is an environmental benefit. To determine a quantitative estimate of this benefit, the water saved, the Council can use the reduced water and wastewater bills paid by consumers to assign a dollar value to this benefit and incorporate it into the resource cost of the conservation measure. While this quantification captures the benefit as it applies to the consumer, the money saved by needing less water, it does not capture the broader environmental benefits of reduced water use, which would be nearly impossible to reasonably quantify.

Due to these challenges, the Council is unable to quantify any distinct and directly attributable environmental benefits through the environmental methodology in the Ninth Plan. However, this does not preclude the Council from recognizing and emphasizing in the resource strategy the value of certain resource choices in helping to mitigate harmful environmental effects. A more systematic breakdown of how different cost and benefits are or are not considered in the planning process, outside of the environmental methodology, can be found in the Quantifiable Resource Cost Framework available on the Ninth Plan webpage.[5]

Due Consideration of Environmental Effects of Generating Resources

The Act requires that in developing the power plan's resource strategy that the Council give "due consideration" to environmental quality and fish and wildlife concerns. Due consideration for environmental quality is pursued through a number of avenues throughout the planning process. It is an explicit goal of the Environmental Methodology, described above, but it also is achieved through the Council's Fish and Wildlife Program, compliance with clean energy regulations, climate model analysis etc. The intention of this section is to narratively address the environmental effects of supply-side generating resources and give due consideration to their impact on the region's environmental quality. These impacts in most cases are not explicitly included in modeling, but can inform decisions and recommendations made by the Council in the power plan.

Every generating resource has adverse effects on the environment, to varying degrees. The following section describes at a high level some of the primary environmental effects of generating resources. This section is not intended to be a comprehensive account of these effects. A more exhaustive analysis was performed for the Seventh Power Plan, and much of that evaluation remains relevant.[6]

[5] https://nwcouncil.box.com/v/ninthplancostframework.

[6] Council Northwest Power and Conservation Council's Seventh Power Plan, Appendix I: Environmental Effects of Electric Power Production.

A few related resources include:

- Council's Methodology for Determining Quantifiable Environmental Costs and Benefits and due consideration for environmental quality to understand how the Council incorporates environmental impacts into its power plan analysis.
- Council's quantifiable resource cost framework to understand how costs and benefits are applied across all resource options and see new generating resource options for the application of quantifiable environmental costs and benefits, along with environmental considerations such as decommissioning costs.[7]
- Section on Select Federal Statutes and Regulation Updates for a description of some of the major federal statutes and regulations that address environmental impacts of generating resources. A brief description of such statutes is found in Technical Appendix B: Existing System Parameters and Policies.

A high-level summary of the environmental effects of generating resources can be found in Table C - 1 below followed by more detailed summaries for each resource.

Table C - 1: Summary Table of Environmental Effects by Generating Resource

Generating Resource	Environmental Effect
Hydropower	Fish and wildlife – blocked fish passage Water quality – changes in temperature and flow rates Erosion and sedimentation Land-Use
Coal	Air emissions – carbon dioxide, particulates, sulfur oxides, nitrogen oxides, mercury, other heavy metals Water quality – discharge of cooling water Reduced visibility – smog The disposal of waste from the coal combustion process requires a significant amount of land and, depending on the waste disposal structure, can pollute surface water.
Nuclear	Radioactive waste from spent fuel Water use Land use
Natural Gas	Greenhouse gas emissions from combustion Water use Pollution from waste heat cooling processes Leakage of methane (fugitive emissions) during the extraction, processing, transportation and storage Drilling for natural gas and the construction of pipeline infrastructure

[7] The full framework can be found at https://nwcouncil.box.com/v/ninthplancostframework.

Generating Resource	Environmental Effect
Biomass	Land use Water use and quality Emissions: nitrogen oxides, sulfur dioxide, carbon monoxide, mercury, lead, volatile organic compounds, particulate matter, carbon dioxide, and dioxins
Geothermal	Land and wildlife disturbances Air and water quantity
Wind - Onshore	Land use Habitat and wildlife interference Decommissioning of plant components
Wind - Offshore	Impacts during construction and decommissioning Noise during construction and operation Disruptions to local ecosystems and behavior of wildlife (marine species)
Solar PV	Land-use Interference with wildlife End-of-life disposal - cadmium and lead in the panels
Battery Storage	Extensive mining, extracting, and processing of the minerals used in a lithium-ion battery: cobalt, nickel, and manganese
Transmission System	Land-use Wildfire risk Interference with wildlife

Environmental Effects of Hydropower Generation

Under the Northwest Power Act, the Council develops a program to protect, mitigate, and enhance fish and wildlife adversely affected by the development and operation of hydropower facilities on the Columbia and its tributaries. To address the effects from the existing system, the Council's 2026 *Columbia River Basin Fish and Wildlife Program* includes measures and objectives to protect and benefit fish and wildlife. Measures to limit the direct impact of hydropower development include fish screens and bypass systems, bypass spills, and fish ladders to help fish navigate through the hydropower dam; minimum flows, flow augmentation requirements and stable storage reservoir operations; and the installation and implementation of systems to maintain powerhouse discharge and minimize or eliminate fluctuations in water and flow levels. Offsite protection and mitigation actions include both habitat protection and improvement measures and artificial propagation facilities and strategies. Mitigation for the effects of the development of the system on wildlife has focused primarily on the offsite acquisition, improvement, and protection of habitat for the affected wildlife species. The representation of the existing hydro system in the power plan assumes implementation of all measures prescribed by the Council's fish and wildlife program, along with any additional existing requirements for system operations.

The principal environmental effects of hydropower are water quality impacts, hydrological impacts, erosion and sedimentation, land-use impacts, and fish and wildlife impacts. The environmental effects associated with any one hydropower project are site specific and therefore can be different when comparing projects; for example, a project that involves adding generators to an existing non-powered dam or other existing water control structure will typically cause less of an incremental environmental impact than a project that requires new dam construction. There are few serious air emissions or solid waste issues associated with hydropower development or operation.

Of particular concern to the Council is the potential impact of hydropower on fish and wildlife. A hydropower dam presents a migration barrier to the passage of upstream (adult) and downstream (juvenile) anadromous and resident fish. Habitat is completely blocked by some projects in the system. At dams that allow passage, juvenile downstream migrants face the risk of mortality at each dam because of passage through turbines, exposure to water supersaturated with nitrogen, delay in start of migration, increased travel times, and increased predation. Filling an impoundment behind a hydropower dam inundates land and transforms a free-flowing river into a lake-like environment. This transition of habitat changes the composition of terrestrial and aquatic biota at the project site which may be beneficial or detrimental to wildlife. System storage operations to optimize power generation also alter flows important for the emergence, rearing, and migration of juvenile salmon and other fish, and for adult spawning.

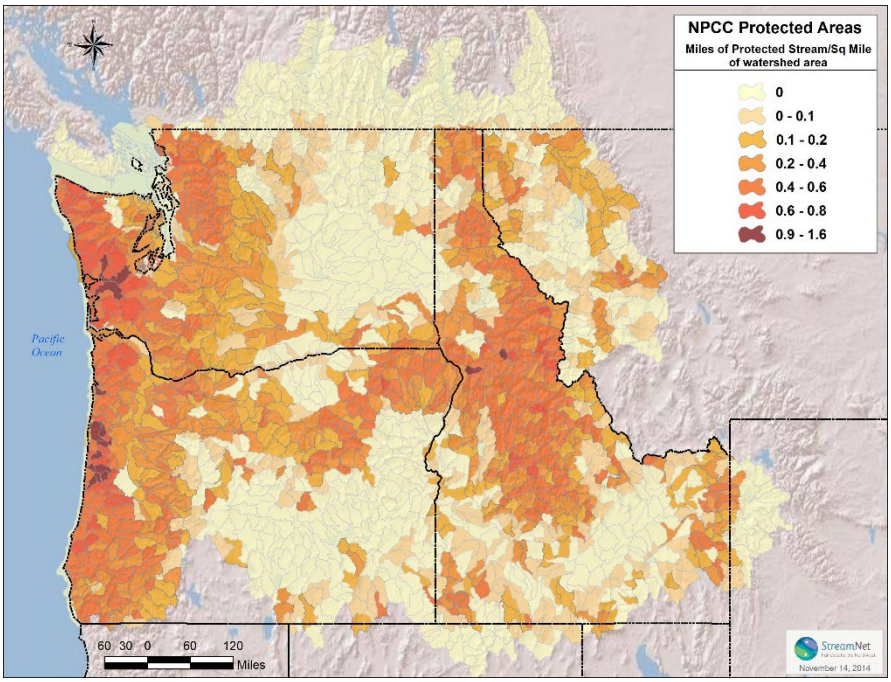
The construction and operation of a hydroelectric project may affect water quality through thermal changes causing wide fluctuation of stream temperatures, nitrogen supersaturation (total dissolved gas), turbidity, and oxygen depletion. A hydroelectric dam slows the movement of water in a river system, which can lead to temperature stratification and oxygen depletion in the reservoir behind the dam. Spill flows from a dam may increase the levels of total dissolved gas in the river downstream. While these water quality changes are not always adverse, they can influence the aquatic environment and can prove lethal for fish and wildlife. Water quality can also affect the aesthetics of the project site.

The process of developing a hydroelectric dam alters the physical hydrology (the movement and distribution of water) of the site and the watercourse. These changes can have significant primary and secondary effects on water quality, habitat, fish and wildlife. The operation of a hydroelectric facility during times of maintenance, outages, or to meet peak energy demands causes fluctuations of water level in both the impoundment and the stream below. These fluctuating water levels may prohibit development of shoreline vegetation, reduce shoreline use by riparian (riverbank or streamside) species of wildlife, and lower reproductive success of fish species that spawn near the impoundment margin. Fluctuations in rivers below dams can strand immature fish on shorelines or in shallow waters and may lead to the exposure of eggs of shoreline spawners and nests of salmonids. Storage dams tend to reduce some of the seasonal fluctuations in river flow, creating a more stable riparian zone and changes in habitat characteristics associated with variable flows. Impound water can flood islands that are important breeding grounds for certain avian species. Issues with erosion and sedimentation may occur during construction and continue long after a project is retired or removed. Changes in the sediment load and flow can affect the natural sediment equilibrium found in free-flowing waters and increase water turbidity due to accretion and settling in the backwaters behind a dam. This can result in increased sediment deposits near the physical dam and decreased sediment

downstream, both affecting the growth of organisms that depend on nutrients carried by the sediment. As the water levels fluctuate, erosion can occur, changing the physical environment. A lack of vegetation along the riverbank can also lead to perpetual carving away of the earth surrounding the water source. The amount of land required for the development of a hydroelectric dam varies significantly depending on the site and project. A storage project can take up thousands of acres, while a small run-of-river project may take up less than an acre. Nonetheless, between the physical infrastructure and the equipment used for construction, land is disturbed, and the surrounding environment is altered.

From the inception of the Program, the Council has supported the concept of protecting some streams and wildlife habitats from hydroelectric development where the Council believes such development would have major negative impacts that could not be reversed. This distinctly limits prospects for large-scale new development that is consistent with the Council's Protected Areas[8] identified on the map in Figure C - 1.

Figure C - 1: NWPCC Protected Areas



[8] https://www.nwcouncil.org/fish-and-wildlife/fw-topics/protected-areas.

Environmental Effects of Coal Generation

Environmental effects of coal generation range from the combustion of fuel to the disposal of waste, and result in significant environmental and human health impacts, notably, air emissions, impacts on water quality, and reduced visibility.

Coal Plant Operation

A coal-fired steam-electric power plant consists of coal receipt, storage, handling and preparation facilities, a furnace and steam generator, a steam turbine and condenser, an electric power generator, a switchyard, flue gas handling and emission control equipment and a closed-cycle condenser cooling system. Coal-fired generation produces significant carbon dioxide emissions, with coal emitting markedly more than natural gas-fired generation. In the region, coal-fired generation has historically accounted for most carbon dioxide emissions from power plant combustion, although that percentage is decreasing with coal unit retirements. In addition to carbon dioxide, coal combustion also causes atmospheric releases of an assortment of pollutants, including particulates, sulfur oxides, nitrogen oxides, and mercury and other heavy metals.

The intake and discharge of the cooling water (which may be contaminated by waste and metals during the cooling process) can affect nearby ecosystems and aquatic life. The disposal of waste from the coal combustion process requires a significant amount of land and, depending on the waste disposal structure, can pollute surface water.

Coal Extraction/Mining

Coal is extracted either from underground mines or surface mines. Underground mines have limited surface impacts, relying on discreet above-ground points of entry to enable miners and equipment to access the coal seam. The development of an underground mine typically involves the transportation of heavy equipment and workers to the site, which may require the construction of new roads. In addition, preparation of the site may entail drilling, blasting, excavation and pile driving. These operations often result in air impacts from fugitive dust and vehicle exhaust, as well as water impacts from altered drainage patterns and increased pollutant and sediment loads in runoff from the site. Wildlife may be affected by associated noise and human activity, as well as habitat disruption.

A surface coal mine causes significantly more visible above-ground impacts than underground mines. The two predominant methods of surface coal mining are mountaintop removal, which commonly occurs in the Appalachian coalfields, and area strip mining, which is typically employed in the Western states. Mountaintop removal mining involves the use of explosives and machinery to access coal seams beneath mountaintops. The displaced rock and dirt are disposed of in adjacent valleys. In addition to causing harmful effluents, mountaintop removal operations often permanently bury headwater streams with overburden and alter flow patterns in associated drainages. Area strip mining uses heavy machinery to remove soil and rock to access underlying coal seams. Large scrapers remove the soil covering the area to be mined, and either stockpile the soil for later reclamation use or use them to reclaim a previously mined area. The overburden beneath the soil is then leveled, blasted and removed to a spoils pile to expose the underlying coal seam. These methods of surface mining

have obvious implications for vegetation and wildlife habitat. Surface mines may also have a detrimental impact on water quality. Surface mining often results in acidic runoff containing harmful levels of sediment, salinity and trace metals.

After coal is mined from either an underground or surface mine, it is typically processed to remove impurities before being transported to a coal plant. The coal cleaning process raises a variety of environmental and human health concerns, primarily resulting from the water effluents associated with the cleaning process. Run-of-mine coal stockpiles may be stored outside, uncovered, which exposes them to wind and rain. Rainwater leaches contaminants from the coal, and the runoff is generally captured in a coal pile runoff pond. These contaminants include metals such as copper, aluminum, nickel, and iron, as well as suspended solids. Coal pile runoff ponds are designed to settle out solids but typically do not treat the water for metal content before discharging. Effluents are also produced in the coal washing process, where much of the non-coal material removed during preparation of the coal is suspended in water and stored in tailings ponds.

In addition to water effluents, coal processing may result in particulate matter air emissions in the form of coal dust during conveyor belt pour off, stockpile construction or consumption, crushing and sorting operations, thermal drying or wind erosion.

Environmental Effects of Nuclear Generation

Nuclear is a carbon-free generating resource, and thus the environmental effects of nuclear generation are focused primarily on water use and radioactive waste from spent fuel disposal. Nuclear power is generated through the fission (splitting of atoms) of uranium, and the spent fuel is therefore radioactive waste. This waste must be disposed of in long-term storage in an environmentally safe way, often in steel-lined concrete canisters above or below ground. Nuclear power plants use a large amount of water for steam production and cooling, which potentially affect nearby ecosystems and aquatic life. In the case of the Columbia Generating Station, its water withdrawal from the Columbia River represents a small fraction of the overall river flow and would have to increase by six times to trigger the Environmental Protection Agency's minimum threshold for industrial water intake regulations.[9] The water that CGS returns to the Columbia River from the wet cooling system is free of radioactive materials; it is separate from the water that is used in the reactor to create steam.

Cooling water withdrawals have the potential to impact water flows and entrain aquatic organisms, while water discharges may occur at temperatures higher than that of the receiving waterbody. The cooling process may also cause toxic materials to dissolve into the water and accumulate as it circulates through the cooling system.

In addition to direct environmental effects from the generation of nuclear energy, there are specific and intricate safety features deployed on site to protect and prevent against any accidental

[9] This threshold is 2 million gallons per day of cooling water, see: https://www.epa.gov/cooling-water-intakes.

widespread contamination event (unmitigated radioactive waste released into the air and/or water) – such as an uncontrolled nuclear reaction, extreme weather event, or earthquake. The Nuclear Regulatory Commission (NRC) regulates and oversees all safety protocols regarding nuclear power plants, and they utilize a strategy of redundant security to minimize all risks.

While the environmental impacts associated with the normal operation of a nuclear power plant are limited, the mining, processing and disposal of nuclear fuel create a variety of adverse environmental effects. Uranium, the typical fuel source for nuclear power generation, is generally mined in open pit mines or extracted through in situ leaching. Preparation of mine sites requires drilling, blasting and road construction, which may disrupt wildlife and existing land uses, in addition to potentially contaminating nearby waterbodies and groundwater. Water runoff from open pit mines may be contaminated with heavy metals and small levels of radioactive material, while in situ leaching operations may also introduce drilling fluids and leaching solutions. In situ leaching involves injecting a fluid (called a "lixiviant") that dissolves uranium and then pumping that uranium containing solution to the surface. That fluid must then be processed to purify and dry the uranium from the solution. Most operating uranium mines in the United States (approximately three percent of total world production) are in situ leaching mines.

Although nuclear electricity generation does not directly produce any significant air pollution, the mining, processing, and transportation of nuclear fuel all require energy inputs, which are typically drawn from other energy sources. Depending on the source of energy, then, these steps may result indirectly in carbon dioxide and other emissions

Decommissioning represents the final phase of a nuclear power plant's lifecycle and may result in a variety of environmental and human health impacts. Decommissioning typically involves the removal and disposal of highly radioactive spent fuel, the demolition of structures and removal of debris, and the clean-up of contaminated soil and groundwater. Most waste produced in decommissioning a nuclear facility is not radiologically contaminated or is minimally radioactive and may be landfilled. Intermediate level waste, such as fuel rod casings and reactor vessel parts, requires shielding and may be disposed of at shallow depths. High level nuclear waste, such as the spent fuel stored on-site in casks or pools, requires cooling and shielding and may be reprocessed or disposed of in deep geological formations. The risk of a large-scale release of radioactive material from decommissioning activities is low, however workers involved in decommissioning a nuclear facility may have heightened risks of exposure due to their interaction with the radioactive debris. The pathways for public exposure to radioactive material may arise from the demolition of structures and debris, which has the potential to release radioactive dust and gas, and the penetration of water into the disposal site, which may dissolve radioactive isotopes and transport them into the water system. These risks can be mitigated through the introduction of proper safety measures, such as protective barriers and monitoring programs. The carbon emissions impact of the decommissioning stage is typically limited to exhaust from worker and construction vehicles and transportation of waste materials.

Environmental Effects of Natural Gas-Fired Generation

Environmental effects of natural gas generation and cogeneration are primarily greenhouse gas emissions from combustion, and water use and pollution from waste heat cooling processes. Natural gas is the cleanest burning of fossil fuels, with about half of the carbon dioxide emissions of coal and about two-thirds that of distillate fuel oil. In addition to carbon dioxide, nitrogen oxide and volatile organic compounds are also released.

The air emissions of principal concern from gas turbines are carbon dioxide, nitrogen oxides (NOx), carbon monoxide and to a lesser extent volatile organic compounds. Sulfur oxide emissions are of potential concern if fuel oil is used. Like all fossil fuel technologies, gas turbines produce carbon dioxide as a product of complete combustion of carbon. Carbon dioxide emission factors are a function of plant efficiency, so newer units in general, and aeroderivative and intercooled units in particular, have lower CO_2 emissions per MW than older units. Though technology for separating CO_2 from the plant exhaust is available, as a practical matter it is unlikely that CO_2 removal technology would be employed for simple-cycle gas turbines because of the relatively low carbon content of natural gas and the relatively small size and limited hours of operation of these units.

When considering the full life cycle of natural gas beyond the combustion of fuel into energy, there are environmental effects from the release or leakage of methane (also known as fugitive emissions) during the extraction, processing, transportation and storage of natural gas. In addition, drilling for natural gas and the construction of pipeline infrastructure have an adverse effect on the land, water, and wildlife.

Unconventional wells are designed to access gas resources in formations with small permeability, which require “stimulation” to start producing. Stimulation increases the permeability of the gas bearing formation. The most common forms of well stimulation are hydraulic fracturing using proppants, hydraulic fracturing using acid, and matrix acidizing. All these forms of stimulation have the potential to adversely impact the environment and human health. Fracking requires the withdrawal of a considerable amount of water, anywhere from 1.5 to over 15 million gallons. This water is mixed with other chemical ingredients to produce fracking fluid. Water withdrawals associated with fracking may cause water quantity impacts in water-constrained areas. Additionally, water quality concerns arise when fracking fluid contaminates freshwater resources, either through migration into freshwater aquifers through inadequately completed wells, or through improper wastewater management. Fracking fluid may contain diesel fuel, polycyclic aromatic hydrocarbons, methanol, formaldehyde, ethylene glycol, glycol ethers, hydrochloric acid, sodium hydroxide, and other toxic compounds.

Environmental Effects of Biomass Generation

The term biomass includes solid fuel, such as wood, wood waste and agricultural residues, as well as methane produced by the decay of organic material in landfills, sewage treatment facilities, and farming operations. Since biomass energy refers to a diverse array of fuels and technologies, the potential environmental and human impacts that result from biomass-fueled electricity generation

are varied. The primary concerns are water and land use impacts associated with feedstock production and air quality concerns relating to biomass combustion.

Biomass generation uses similar technology to coal and natural gas and therefore is subject to emissions arising from the production process; however, in general biomass emits fewer pollutants than its fossil fuel counterparts. The primary air emissions caused by biomass combustion include nitrogen oxides, sulfur dioxide, carbon monoxide, mercury, lead, volatile organic compounds, particulate matter, carbon dioxide, and dioxins. Biomass generation can be considered a carbon dioxide-reducing resource only if re-plantation of the spent fuel occurs (e.g. woody residues). Most existing biomass projects in the region are fueled by already spent resources rather than resources grown for the purpose of energy production, for example animal waste, woody residues, and municipal garbage, and therefore the impact to land and water use to supply the fuel is minimal as it already exists. Depending on the type of technology and fuel used in power production, there are greenhouse gas emissions and water quality issues associated with biomass. Cooling water can affect nearby land and water sources, depending on where/how it is used. If a closed-loop system is utilized by the power plant, there are fewer impacts to nearby water sources than a once-through or open loop cooling system.

Environmental Effects of Geothermal Generation

Environmental effects of geothermal generation are land and wildlife disturbances, air and water quantity and quality. Much like wind and solar, prospective geothermal power plants must undergo extensive environmental impact reviews that mitigate many land and wildlife impacts. While geothermal plants can take up to several hundreds of acres of land during development, much of that land can be reclaimed and repurposed once construction is complete. Air and water effects depend largely on the type of technology and open/closed loop cycle utilized by the power plant. There are few emissions from binary, closed-loop geothermal power plants as the water and air vapors are re-injected into the production cycle. Open-loop cycle plants emit primarily carbon dioxide and some methane, although it is at an amount that is equivalent to 30 percent of a conventional coal plant.

Environmental Effects of Wind Generation

Onshore Wind

Environmental effects of wind power generation are primarily land use, habitat, and wildlife interference. There are no greenhouse gas emissions related to the generation of power itself. While wind farms use a significant amount of land in total area (the acreage is site specific, depending on the configuration and geography of a project), much of that land is either undisturbed by development or multi-purposed. Wildlife interference occurs in two ways: direct mortality due to collisions with the wind turbines and indirect impacts to wildlife due to the loss of habitat in which the wind project resides, including blockage of migration pathways.

Bird deaths are primarily the result of direct contact with spinning wind turbines, the tips of which can travel at speeds ranging from 150 to 200 miles per hour. Most of the bird types affected by wind turbines are songbirds. Eagles and other raptors may be affected by the operation of wind facilities in

and around their soaring locations and through direct contact with spinning turbine blades. Environmental Impact Statements prepared in support of wind projects in the Northwest identify several special-status raptor species that may be affected by wind development including the Northern Goshawk, Ferruginous Hawk, and the Peregrine Falcon. The Greater Sage Grouse is a species of particular concern, because its range coincides with prime wind resources in the region. The sage grouse is primarily affected by habitat disruption resulting from wind development, because the animals tend to avoid human infrastructure. Other bird species that may be vulnerable to wind project development as well, including: the Sage Sparrow, Loggerhead Shrike, Lewis' Woodpecker and Mountain Quail. Many bat species are also affected by wind energy development, through both contact with the spinning blades and contact with areas of rapidly changing pressure caused by the turbines. Abrupt changes in pressure may cause barotrauma in bats, resulting in internal hemorrhaging that can be fatal.[10]

As wind turbines reach the end of their useful life, decommissioning of plant components and the magnitude of waste created becomes an issue. Most of the wind turbine components can be recycled, salvaged, repurposed, or sold on a secondary market. However, there is not currently an adequate solution for decommissioned wind turbine blades – composed of composite fiberglass and resin. Oftentimes, blades are simply disposed of in landfills because it is the most economic option. The size of the blades can create a substantial issue for local landfills with limited capacity to grapple with, and transportation of blades to designated waste areas can get very expensive.

Much of the land and wildlife effects are mitigated during the siting and licensing of wind projects, although the effects of a significant deployment of onshore wind in a short amount of time are not yet fully understood.

Offshore Wind

The environmental effects of offshore wind include impacts during construction and decommissioning, noise during construction and operation, and disruptions to local ecosystems and behavior of wildlife. The development of an offshore wind project includes significant machinery, complex logistics, and major installation of equipment beyond the wind turbine itself (e.g. underwater transmission cables to transport the electricity to onshore substations). All of this leads to the disturbance of the existing habitat.

With the introduction of equipment above, and below the surface of the water, many marine species are affected. Under the water, species such as mussels and algae are attracted to and can colonize the structure and cables. This can cause the creation of artificial reefs and an increase in marine life and species diversity. One drawback is that an artificial reef can also attract predators and introduce new, invasive species to the ecosystem, leading to predation and threatening the existing species through competition of habitat and food sources. Underwater structures may also be spread out over a wide area, which can lead to disruption and entanglement of marine populations that typically

[10] https://rewi.org/wp-content/uploads/2025/09/REWI_Wind-Interactions-Summary_2025.pdf.

forage and migrate through the offshore wind project area. At the surface and above the water, structures pose similar risks of collision and entanglement to seabirds (which may be more attractive to the area due to the increased marine life) although the risk is less as the structures are large enough to be visible. If equipment is close to the shoreline, breeding grounds may also be disrupted or affected. Noise, during construction and operation, may disturb the wildlife in the area, although severity is likely dependent on the species.

Environmental Effects of Solar PV Generation

Environmental effects of solar PV generation are mainly land-use, interference with wildlife, and end-of-life disposal. Energy production from solar PV plants does not contribute to the release of greenhouse gases.

An environmental concern is the proper disposal of solar panels at the end of their useful life. Solar panels contain hazardous materials that if disposed of improperly, could potentially pose a risk to the environment. The primary concern for toxicity is the cadmium and lead in the panels. However, panels are mostly comprised of glass, aluminum, and plastics with very little lead or cadmium (depending on the technology), and these components encapsulate the limited amount of lead and protect it from the environmental and harsh weather conditions. Thus, even when disposed of in a landfill, there is very minimal risk of toxicity.

Much of the land and wildlife effects are mitigated during the siting and licensing of solar PV projects, although the effects of a significant deployment of solar PV in a short amount of time is not yet fully understood. In the 2021 Power Plan the Council recommended that siting authorities should work to ensure that new renewable resource development is carried out in a manner that protects wildlife, fish, and cultural resources of the Pacific Northwest. Emphasizing the importance of “least impact, less conflict” siting principles to push development away from high value lands and encouraging deliberate, strategic outreach and engagement in siting processes with fish and wildlife agencies, tribes, and communities directly affected by development. The recommendation was explicit about prioritizing tribal consultation to better understand and preserve cultural resources and traditional uses in the vicinity of developments.

The production of solar PV panels requires the acquisition of raw materials, the use of toxic chemicals, the consumption of electricity, and the disposal of waste products, all of which have attendant environmental risks. In addition to silicon, which is relatively abundant and the largest component of a solar panel, the production of a PV system typically requires rare or precious metals, such as silver, tellurium and indium. These rare metals may be mined by exploited workers and supplied from areas of conflict. Although abundant, silica can cause lung disease silicosis in workers responsible for mining the material. Silica is generally mined in the form of quartz, which must be initially refined into silicon and then into polysilicon before it may be used in a solar panel. The initial refining process requires the use of energy-intensive furnaces, the operation of which may result in greenhouse gas and other air emissions depending on the energy source used. Thin-film manufacturing methods, which represent a less material- and energy intensive manner of manufacturing PV panels, may obviate the need for many of the steps described above. But thin-film technologies typically require components that contain cadmium which is a carcinogen and

genotoxin. As a result, thin-film manufacturers are working on reducing or eliminating the need for cadmium in their products. The overall environmental impacts of solar panel production largely depend on the materials and processes used by the panel manufacturer.

Habitat disruption is the primary risk to plants and wildlife posed by utility-scale solar PV. The best solar resources in the Northwest are typically situated in high desert areas, so desert species are the most vulnerable to solar development. Utility-scale solar facilities typically consist of multiple rows of solar panels mounted on a concrete foundation. Once constructed, plants and wildlife are excluded from these facilities, so utility-scale PV development reduces available habitat. Solar PV development also brings with it human noise, activity and infrastructure, which may affect adjacent wildlife. Contact with increased vehicular traffic to and from the site, both during construction and operation could result in additional harm to wildlife. Mitigation measures, including limiting development to disturbed areas or existing facilities, establishing protective buffers between the facility and sensitive areas, and avoiding significant activity around the facility during mating periods can limit the risk of wildlife disruption.

Environmental Effects of Battery Storage

While environmental effects of battery storage differ based on technology and chemical properties, for lithium ion batteries and others, the primary effects of battery storage generation focus on emissions resulting from the primary source of energy charging the battery (for example, a wind plant or gas plant providing energy to be stored in the battery for discharge at a later time) and proper disposal of the battery components at the end of useful life. In addition, there are significant environmental, societal, ethical, and human rights impacts that can result from the improper or extensive mining, extracting, and processing of the minerals used in a lithium-ion battery. Responsible sourcing of these minerals is key if battery storage is set to play a large role in storing electricity and electrifying transportation.

Lithium-ion batteries contain cobalt, nickel, and manganese, which are all considered toxic heavy metals that if accumulated in large enough concentrations (through direct contact when working in both extraction and disposal methods) can cause human health hazards. These raw materials are also considered critical minerals, in that they are economically and strategically important and do not have readily available substitutes if/when sources are depleted. Finally, lithium-ion batteries are considered hazardous waste due to both their chemistries and combustibility. This all makes the proper disposal of the batteries at the end of their lifecycle very important. If batteries are disposed of in landfills, we not only risk toxic leeching or fire hazards if disposed of improperly (risks vary depending on technology and manufacturer), but we also risk losing the critical minerals. Since the cost of batteries has declined significantly, there are minimal incentives to salvage and resell components of the batteries. To minimize and avoid the waste accumulated through direct disposal in landfills, lithium-ion recycling initiatives have been launched.

Environmental Effects of Transmission System

Environmental impacts of transmission systems include habitat destruction, soil erosion, and water pollution during construction. In addition, long-term issues like habitat fragmentation, noise, and the

risk of wildfires during operation. Construction can cause temporary and permanent damage to ecosystems, and ongoing maintenance can continue to disrupt wildlife and habitat.

Technical Appendix D: Climate Model Data and Assumptions

Contents

Integrating Climate Policies and Data 2
Climate Model Data 2
Incorporating Climate Model Data into Analytical Tools 3
Summary of the RMJOC Climate Model Data and Scenarios 5
Global Climate Models Selected by the RMJOC 6
The 19 RMJOC Climate Scenarios 8
The Subset of RMJOC Climate Scenarios for the Power Plan 11
The Three Selected Climate Scenarios 12
Selecting an Additional RMJOC Climate Scenario 15
Staying With the Original Three Selected Climate Scenarios 17
The Climate Scenario Years Used in the Ninth Power Plan 20
In-Region Climate Scenario Data 21
Trends in Historical and Climate Scenario Streamflows 23
Trends in Historical and Climate Scenario Temperatures 45
Climate Scenario Wind Generation Profiles 65
Climate Scenario Solar Generation Profiles 93
Out-of-Region Climate Data 112
Temperature Data 113
Streamflow Data 114
Wind Data 116
Solar Data 118

Integrating Climate Policies and Data

The Council first started using climate model data to inform its power planning in the Seventh Power Plan. There are a few substantive ways in which climate data affects the power plan. First, long-term trends in temperature will alter the magnitude and seasonal pattern of electricity demand. Next, since temperature determines whether precipitation falls as rain or snow at a location, then trends in temperature will also alter (magnitude and seasonal pattern of) snowpack on mountains and streamflow in rivers, and thus potential electricity generation from hydro-projects along the river. Furthermore, since temperatures at the extremes (i.e., very high and very low) are correlated with very low wind speeds, then trends in temperature could alter the potential electricity generation from wind farms. Additionally, state policies and laws enacted to reduce greenhouse gas emissions will affect existing resource operations and limit future resource choices. The combined effects of those policies, temperature and other factors will impact the availability of new resources, including energy efficiency and demand response. All these effects must be taken into account to ensure that the Council's resource strategy will result in an adequate, efficient, economical and reliable future power supply. This section focuses on how climate model data are incorporated into the Council's analytical tools, including updates to the approach for the Ninth Power Plan.

Climate Model Data

In 1988, the United Nations Environment Programme (UNEP) and the World Meteorological Organization (WMO) established the Intergovernmental Panel on Climate Change (IPCC), which was subsequently endorsed by the United Nations General Assembly.[1] The IPCC was established to assess available scientific, technical, and socio-economic information concerning climate change, its potential effects, and options for adaptation and mitigation. The IPCC's purpose is to collect and review the most recent scientific information produced worldwide relevant to the understanding of climate change. It does not conduct any research on its own nor does it monitor climate-related data. It is open to all member countries of the United Nations and currently has 195 participating countries that review all scientific material to ensure an objective and complete assessment of current information.[2]

In November of 2014, the IPCC completed its Fifth Assessment Report (AR5)[3] which, among other topical sections, includes a comprehensive assessment of the physical science basis of climate change. In particular, a working group of the IPCC analyzed global climate models (also abbreviated as GCMs) developed by various international participating organizations.[4] The various GCMs forecast long-term changes in the Earth's climate including the effects of greenhouse gases on temperature

[1] See "*IPCC Factsheet: Timeline – highlights of IPCC history*" at https://www.ipcc.ch/site/assets/uploads/2024/04/IPCCFactSheet_Timeline.pdf.
[2] See https://archive.ipcc.ch/organization/organization.shtml.
[3] See "*AR5 Climate Change 2014: Mitigation of Climate Change*" at https://www.ipcc.ch/report/ar5/wg3.
[4] See "*CMIP5 - Coupled Model Intercomparison Project Phase 5*" at https://pcmdi.llnl.gov/mips/cmip5.

and precipitation. The models also take into consideration the interaction of the atmosphere, oceans, and land surfaces. Each of these models has been calibrated to some degree and crosschecked against other such models to provide greater confidence in their forecasting ability.

There were at least 31 different GCMs that were used to project future changes in temperature and precipitation. Every one of these models, to varying degrees, forecasted a warming trend for the Earth. Each used sophisticated mathematical techniques to simulate changes in temperature as a function of atmospheric and other conditions. Like all fields of scientific study, however, there are uncertainties associated with GCM analyses, such as the effects of weather and ocean conditions, that are not as well-understood as scientists would like. Nonetheless, scientists are generally confident about GCM projections for large-scale global areas.

Unfortunately, forecasts on a large spatial scale are of little use to power planners in smaller sub-regions, such as the Pacific Northwest. Therefore, methods to downscale output from the GCMs to a more granular scale were developed by the River Management Joint Operating Committee (RMJOC) which consists of staff from three federal agencies, Bonneville Power Administration (BPA), the Army Corps of Engineers, and the Bureau of Reclamation, as well as climate scientists from the University of Washington and Oregon State University. The downscaling methodology and resulting finer spatial scaled GCM data are described in detail in a RMJOC report.[5]

The RMJOC climate model data were developed for the Pacific Northwest region and are considered as "in-region." The Council's analytical tools use the RMJOC and other related climate model data to simulate operations of power systems in the Northwest. The "in-region" climate model data are discussed in detail from the section "*Incorporating Climate Model Data into Analytical Tools*" to those sections under "*Climate Scenario Solar Generation Profiles*" in this Appendix.

In developing this Power Plan, the Council's analytical tools also simulate power systems in the Western Electricity Coordinating Council[6] (WECC) that are outside of the Pacific Northwest. However, since the RMJOC climate model data are not available for these WECC "out-of-region" power systems, other sources of climate model data are used, and they are discussed in the last section "*Out-of-Region Climate Data*".

Incorporating Climate Model Data into Analytical Tools

The Council uses climate model data to inform hydro conditions, loads, and renewable profiles. The downscaled climate model data include projected future daily maximum and minimum temperatures and daily averaged precipitation for roughly every four-by-four square mile area within the Pacific Northwest region. The forecasted temperature and precipitation data are inputs into various

[5] See "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.
[6] See https://www.wecc.org/.

hydrological models to develop a reasonable range of natural (unregulated) river flows.[5] When irrigation withdrawals and returns and evaporation are taken into account, the natural flows then become the modified flows. More specifically, the RMJOC climate model modified flows were calculated with the effects of historical irrigation depletions of year 2008, which were also used in developing the 2010 Level Modified Streamflows.[7] The modified flows at various locations along rivers in the region are among the many inputs into the Council's adequacy model and capital expansion model, GENESYS and OptGen, respectively, to simulate operations of various hydro-projects for power generation and other non-power functions (for example, flood risk management).

Furthermore, the climate model temperatures are also used, among other inputs, in the Council's load-forecast models to estimate future electricity demand.[8] The forecasted demand is then used to provide a starting point for not only the broader regional power system analysis, but also potentially available energy efficiency and demand response.[9]

Unlike the streamflow and temperature data, climate model forecasted wind speed data are not included in the RMJOC data sets. Fortunately, they are available at the Climatology Lab at the University of California, Merced.[10] The downloaded daily averaged wind speed are then used to estimate a set of future hourly wind generations which become inputs in the GENESYS and OptGen models.

Lastly, even though climate model forecasted solar radiation data (also not included in the RMJOC data sets) are available for download from the Climatology Lab, they are not directly used to model future solar generation since there are concerns about the GCMs' ability to accurately simulate cloud cover over the downscaled spatial grids.[11] Instead, climate model diurnal temperature ranges are used as a proxy for the projected solar radiation. These climate model diurnal temperature ranges along with historical diurnal temperature ranges and historical solar radiation data are combined to estimate a set of future hourly utility-scale and behind-the-meter solar generations. The utility scale solar generation becomes an input into the GENESYS and OptGen models, while the behind-the-meter solar shape is used to calculate levelized costs.[12] Both types of solar generation include effects of smoke modeled from historical wildfire patterns.[13]

For simplicity, the climate scenario modified streamflows, forecasted climate wind and solar generation, and electric demand forecasted using climate scenario temperature data are referred to

[7] See https://www.oregon.gov/owrd/WRDReports/appendix_d_flow-data-set-res-sim-analysis.pdf for more details.
[8] See Technical Appendix F - Electricity Demand Forecast in the Ninth Power Plan for more details.
[9] The Council also used these projected temperatures to estimate the savings potential for specific weather sensitive efficiency measures, such as heating measures, to reflect how those opportunities will save under future temperatures. Also reference the section how climate model data are incorporated in Energy Efficiency (EE) and Demand Response (DR) models.
[10] Climatology Lab: https://www.climatologylab.org/maca.html.
[11] Discussions during the Climate and Weather Advisory Committee Meeting on 12/04/2024.
[12] See Technical Appendix J - Rooftop Solar Methodology and Potential in the Ninth Power Plan for more details.
[13] See wildfire methodology section in Technical Appendix G - New Generating Resources for more details.

as climate-informed data. Along with other types of data, they are used in the Council's adequacy model, GENESYS, to assess adequacy reserve margins (ARM). Then the ARM, the climate-informed data, and other relevant resource data, are used as inputs into the Council's regional capital expansion model, OptGen, to develop 20-year resource strategies for the Ninth Plan.

Summary of the RMJOC Climate Model Data and Scenarios

For the Ninth Plan, the Council decided to continue to use climate data developed by the RMJOC, as was done in the previous 2021 Power Plan. A comprehensive analysis of the RMJOC climate data is available in a report (RMJOC I).[14] In the report, RMJOC staff selected 19 climate scenarios for reservoir regulation studies to model and analyze climate impacts on hydro power, flood risk management, water supply, ecosystem, and biological operations, among other topics of interest. Results of the hydro-regulation studies are published in another RMJOC Report (RMJOC II).[15] Methods for selecting the previous subset are described in detail in the "*Climate Change Scenario Selection Process"* supporting material of the 2021 Power Plan.[16] Since data from any selected RMJOC climate scenarios are inputs into many of the Council's models used for the Ninth Power Plan, this section is a summary of the climate scenarios from the RMJOC I report.

The RMJOC climate data were developed from a subset of GCMs from the Coupled Model Intercomparison Project Phase 5 (CMIP5) which were completed in 2014.[17] Subsequently, from 2019 to 2022, a newer set of GCMs became available from CMIP6.[18] Some members of the Council's Climate and Weather Advisory Committee (CWAC) have suggested using climate data from the newer set of CMIP6 GCMs. However, the streamflow data, which is used as an input in the Council's adequacy and capital expansion models, is not an output of GCMs. Rather, it was the RMJOC staff, many of whom have background in regional hydrology, that calculated streamflow data from temperature and precipitation data, which are outputs of CMIP5 GCMs. The RMJOC streamflow data were calculated using various hydrological models tuned for the Pacific Northwest region. There is yet no regional streamflow data calculated from outputs of CMIP6 GCMs, and therefore, the Council continues to use climate data from the CMIP5 GCMs.

[14] "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.
[15] https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-ll.PDF.
[16] https://www.nwcouncil.org/2021powerplan_climate-change-scenario-selection-process.
[17] See "*CMIP5 - Coupled Model Intercomparison Project Phase 5*" at https://pcmdi.llnl.gov/mips/cmip5.
[18] See "*CMIP6 - Coupled Model Intercomparison Project Phase 6*" at https://pcmdi.llnl.gov/CMIP6.

Global Climate Models Selected by the RMJOC

Climate scientists at Oregon State University and the University of Washington, in collaboration with RMJOC staff, selected 10 GCMs from CMIP5 that better replicate historical climate data for the Pacific Northwest region and the larger western North America and northeast Pacific. The 10 selected GCMs are listed in Table D - 1.

Table D - 1: The 10 Global Climate Models selected by the RMJOC

1. CanESM2	6. HadGEM2-CC
2. CCSM4	7. HadGEM2-ES
3. CNRM-CM5	8. inmcm4
4. CSIRO-Mk3-6-0	9. IPSL-CM5-MR
5. GFDL-ESM2M	10. MIROC5

For each of the 10 GCMs, output data were calculated for several representative concentration pathways (RCPs). The RCP is in units of watts per square meter and represents the difference of energy flux radiated by the atmosphere back to the surface between the chosen pre-industrial year of 1765 and the year 2100. For example, for GCMs with RCP8.5, the atmosphere for the year 2100 will radiate to the surface with an *additional* 8.5 W/m^2 energy flux than it did for the year 1765. This increase in energy radiated on the surface of the Earth, or positive radiative forcing, will lead to higher warming for 2100 relative to 1765. Furthermore, it has been estimated that relative to 1765, radiative forcings for 1950, 1980 and 2011 were about 0.57 W/m^2, 1.25 W/m^2 and 2.29 W/m^2 respectively (see IPCC AR5 WG1 Figure SPM.5[19]). Thus, positive radiative forcing has been increasing over the recent decades and so has warming. The RMJOC selected GCMs with RCP4.5 and RCP8.5.

Up to the time of the RMJOC Report,[20] greenhouse gas emissions most closely followed those consistent with RCP8.5 radiative forcing. Since then, there has been debate about the plausibility of RCP8.5 over the long term.[21] However, RCP8.5 is still considered a likely scenario and appropriate for planning purposes out to at least 2050,[22] which is about the time horizon of this study. Moreover, for the Columbia River Basin there is a large overlap in regional GCM projections of temperature and

[19] Intergovernmental Panel on Climate Change, Assessment Report 5, WG1 Figure SPM.5: https://www.ipcc.ch/report/ar5/wg1/summary-for-policymakers/figspm-05.

[20] See "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

[21] Hausfather, Z., & Peters, G. P. (2020). Emissions - the "business as usual" story is misleading. Nature, 577(7792), 618-620. https://doi.org/10.1038/d41586-020-00177-3.

[22] Schwalm, C. R., Glendon, S., & Duffy, P. B. (2020). RCP8.5 tracks cumulative CO2 emissions. Proceedings of the National Academy of Sciences, 117(33), 19656-19657. https://doi.org/10.1073/pnas.2007117117.

precipitation from RCP4.5 and RCP8.5 to 2050.[23] Therefore, the Council decided to use only GCMs with RCP8.5 for the Ninth Plan, matching the RMJOC decision to also choose the RCP8.5 GCMs for its hydro-regulation studies.

The 10 selected CMIP5 GCMs have spatial grids with resolutions between 47 miles to 186 miles. However, grids with these distances are too coarse to adequately capture the complex terrain and highly varied climate across the Columbia River Basin. Also, the coarse spatial grids might not be close to locations of interest for representative cities of the 13 Northwest balancing authorities (such as airports), whose climate scenario temperature data are used in the Council's load forecast models. Therefore, to make the climate data more useful, the RMJOC transformed the original coarse grid into a more granular grid of about 4 miles by 4 miles using two statistical methods: the Bias-Corrected Spatial Disaggregation (BCSD) downscaling and Multivariate Adaptive Constructed Analog (MACA) downscaling.

With the two downscaling methods, RMJOC staff were able to calculate for the 10 GCMs downscaled temperature and precipitation data on many grid points over the Northwest. Because of using two downscaling methods, the original 10 CMIP5 GCMs in Table D - 1 expanded to 20 downscaled GCMs and are listed in Table D - 2. The downscaling method is expressed in bold texts.

Table D - 2: The 20 RMJOC downscaled Global Climate Models

CanESM2_**BCSD**	CanESM2_**MACA**	HadGEM2-CC_**BCSD**	HadGEM2-CC_**MACA**
CCSM4_**BCSD**	CCSM4_**MACA**	HadGEM2-ES_**BCSD**	HadGEM2-ES_**MACA**
CNRM-CM5_**BCSD**	CNRM-CM5_**MACA**	inmcm4_**BCSD**	inmcm4_**MACA**
CSIRO-Mk3-6-0_**BCSD**	CSIRO-Mk3-6-0_**MACA**	IPSL-CM5-MR_**BCSD**	IPSL-CM5-MR_**MACA**
GFDL-ESM2M_**BCSD**	GFDL-ESM2M_**MACA**	MIROC5_**BCSD**	MIROC5_**MACA**

The climate data (precipitation and temperature) from the 20 downscaled GCMs in Table D - 2 were used as inputs into hydrological models to generate natural streamflow data. It should be noted that these natural streamflows do not take into consideration any irrigation, evaporation, or regulation from hydro-projects. RMJOC staff used four hydrological models: the Variable Infiltration Capacity (VIC) Model developed at the University of Washington (VIC-P1), at the Oak Ridge National Laboratory (VIC-P2), and at the National Center for Atmospheric Research (VIC-P3), and the Precipitation Runoff Modeling System (PRMS-P1) Model.

Thus, the four hydrological models produced 80 climate scenarios of natural streamflows from the 20 downscaled GCMs in Table D - 2. Since it is not practical to list all 80 scenarios in a table, an example is presented for one downscaled GCM to show the transformation of its climate data into climate scenario streamflows. The downscaled CanESM2_**BCSD** model listed in Table D - 2 will produce four scenarios: CanESM2_**BCSD**_***VIC_P1***, CanESM2_ **BCSD**_***VIC_P2***, CanESM2_**BCSD**_***VIC_P3***, and

[23] Rupp, D. E., Abatzoglou, J. T., & Mote, P. W. (2017). Projections of 21st century climate of the Columbia River Basin. Climate Dynamics, 49(5), 1783-1799. https://doi.org/10.1007/s00382-016-3418-7.

CanESM2_**BCSD**_ ***PRMS_P1***, where the hydrological models are expressed in italic bold texts. These four scenarios have different streamflows but the same temperature since hydrological modeling does not affect temperature. Therefore, even though there are 80 scenarios with climate model natural streamflows, there are only 20 unique scenarios for climate model temperatures as listed in Table D - 2.

RMJOC staff performed extensive analyses of the 80 climate scenarios, and the following are excerpts from the executive summary in the RMJOC Report[24]:

- Temperatures have already warmed about 1.5°F in the region since the 1970s (which refers the 30 years from 1970 to 1999). They are expected to warm another 1 to 4°F by the 2030s (which refers to the middle decade of the near-future 30 years, from 2020 to 2049).
- Temperatures are likely to warm 3 to 6°F over what is currently observed in the basin by the 2070s if RCP4.5 emissions pathways are attained. If current trajectory RCP8.5 emissions pathways are realized, though, 4 to 10°F of warming above what is currently observed will be likely by the 2070s (which refers to the middle decade of the far-future 30 years, from 2060 to 2089).
- Warming is likely to be greatest in the interior, with a greater range of possible outcomes, with less pronounced warming near the coast.
- Future precipitation trends are more uncertain, but a general upward trend is likely for the rest of the 21st century, particularly in the winter months. Already dry summer months could become drier.
- Average winter snowpacks are very likely to decline over time as more winter precipitation falls as rain instead of snow, especially in the US side of the Columbia Basin.
- By the 2030s, higher average fall and winter flows, earlier peak spring runoff, and longer periods of low summer flows are very likely. The earliest and greatest streamflow changes are likely to occur in the Snake River Basin, although that is also the basin with the greatest modeling and forecast uncertainty.
- In the Willamette Basin, fall and winter flows are likely to increase. A slight decrease in spring flows is possible, with a longer period of low summer flows more likely than not.

The 19 RMJOC Climate Scenarios

Because a hydro-regulation study for just one scenario requires considerable time and resources to complete, the RMJOC staff decided to study hydro-regulation for only a representative subset of the 80 scenarios. The representative subset of 19 climate scenarios is listed in Table D - 3 below.

[24] See "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

Table D - 3: The 19 Climate Scenarios Selected by the RMJOC for Hydro-Regulation Studies

A: CanESM2_RCP85_**BCSD**_***VIC_P1***	**K:** GFDL_ESM2M_RCP85_**MACA**_***VIC_P2***
B: CanESM2_RCP85_**MACA**_***PRMS_P1***	**L:** HadGEM2-CC_RCP85_**BCSD**_***VIC_P1***
C: CCSM4_RCP85_**BCSD**_***VIC_P1***	**M:** HadGEM2-CC_RCP85_**MACA**_***VIC_P1***
D: CCSM4_RCP85_**MACA**_***VIC_P3***	**N:** inmcm4_RCP85_**BCSD**_***PRMS_P1***
E: CNRM-CM5_RCP85_**BCSD**_***VIC_P2***	**O:** inmcm4_RCP85_**BCSD**_***VIC_P2***
F: CNRM-CM5_RCP85_**MACA**_***VIC_P1***	**P:** inmcm4_RCP85_**MACA**_***VIC_P3***
G: CNRM-CM5_RCP85_**MACA**_***VIC_P3***	**Q:** IPSL-CM5A-MR_RCP85_**MACA**_***VIC_P2***
H: CSIRO-Mk3-6-0_RCP85_**BCSD**_***PRMS_P1***	**R:** MIROC5_RCP85_**BCSD**_***PRMS_P1***
I: GFDL_ESM2M_RCP85_**BCSD**_***VIC_P2***	**S:** MIROC5_RCP85_**BCSD**_***VIC_P3***
J: GFDL_ESM2M_RCP85_**MACA**_***VIC_P1***	

These 19 scenarios were selected by the RMJOC to cover a wide range of differences in hydrological conditions between the 2030's time period (the 30 years from 2020 to 2049) and a historical period (the 30 years from 1976 to 2005) for 14 hydro-projects throughout the Columbia River Basin. A map of the 14 hydro-projects in the red circles is plotted Figure D - 1.

Figure D - 1: The 14 Hydro-Projects in the Red Circles[25]

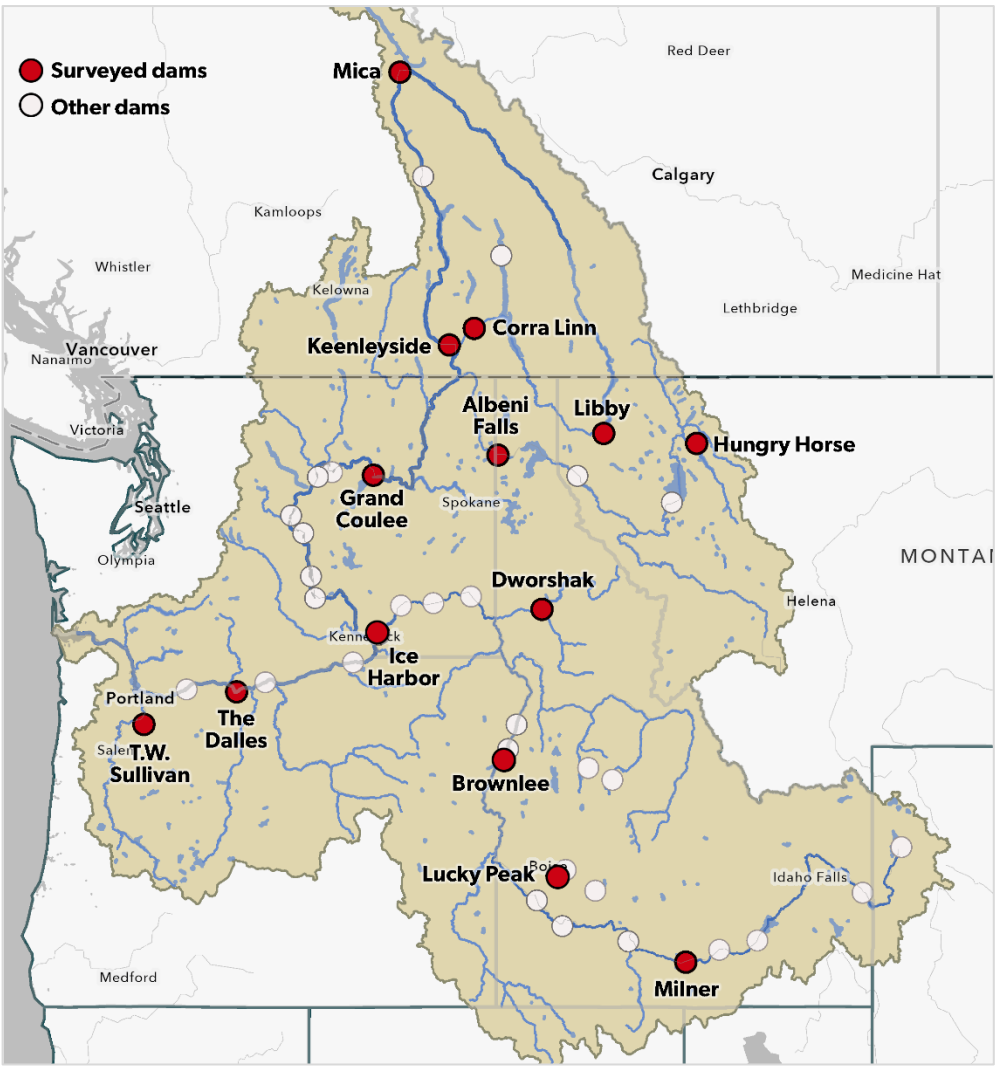


Figure D - 1 shows a map of the 14 hydro-projects, plotted in the red circles, whose streamflow metrics were used to select the 19 RMJOC climate scenarios. The 14 hydro-projects are Mica, Keenleyside (or Arrow), and Cora Linn in Canada, and Hungry Horse, Libby, Albeni Falls, Grand Coulee, Dworshak, Ice Harbor, The Dalles, T. W. Sullivan, Brownlee, Lucky Peak, and Milner in the United States. The hydrological conditions are characterized by six streamflow metrics: river-flow volume for the entire year and for the winter, spring, and summer periods, winter-to-spring volume ratio, and annual half-volume timing (which is the date on which half the annual volume at The Dalles has passed). RMJOC staff then developed an algorithm based on these six streamflow metrics for the

[25] Figure D-1 reproduces the same information on the 14 hydro-projects as Figure 76 in "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

14 hydro-projects to select the subset of 19 out of 80 climate scenarios.[26] For these 19 climate scenarios, RMJOC staff also performed hydro-regulation studies and published the results and analyses in another RMJOC report.[27]

The RMJOC shared its climate model and related data with the Council, which include modified streamflows (which do contain effects of irrigation and evaporation, but not regulation from hydro projects), flood-control and refill rule-curves, and operating constraints for various hydro-projects. These hydro data are needed for the Council's resource adequacy and capital expansion models, GENESYS and OptGen, respectively. Analyses of the climate model streamflow data are presented in a subsequent section.

In addition to the hydro related data, the RMJOC also shared climate model temperature data at 26 locations in the Northwest that could represent the 13 Northwest balancing authorities. The temperature data are inputs into Council's load forecast model.[28] Some representative regional temperatures are analyzed in detail in a later section.

As discussed previously, climate model wind and solar data are not available from the RMJOC data set but are available at the Climatology Lab at the University of California, Merced.[29] The calculations of climate scenario wind and solar generations, which are inputs into the Council's simulation models, are described in detail in subsequent sections.

Finally, since the full designation for each of the 19 climate scenarios in Table D - 3 is quite long, for convenience, in subsequent sections the scenarios are referenced by the assigned alphabetical indices, from A to S, which are printed in bold texts. It should also be noted that the pair of scenarios in each of the four sets, (F, G), (J, K), (N, O) and (R, S), have the same climate temperature since they come from the same GCM and are calculated with the same downscaling method but differ only in the hydrological models used (which does not affect temperature). Because of duplications in temperatures in these four pairs of scenarios, there are only 15 unique scenarios for climate temperatures in contrast to the 19 unique scenarios for climate streamflows.

The Subset of RMJOC Climate Scenarios for the Power Plan

As discussed in a previous section, for the Ninth Plan, the Council proposed to use the same representative subset of three climate scenarios out of the 19 RMJOC climate scenarios as was done in the previous 2021 Power Plan. The selected RMJOC climate scenarios and their relevant properties

[26] See "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.
[27] https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-ll.PDF.
[28] See Technical Appendix F - Electricity Demand Forecast in the Ninth Power Plan for more details.
[29] Climatology Lab: *https://www.climatologylab.org/maca.html*.

are presented in this section. Furthermore, there is also a discussion on adding another climate scenario to the existing three scenarios in the subset so that together they are more representative of the entire ensemble of 19 RMJOC climate scenarios. Council staff presented the two proposed subsets and their analyses to the Climate and Weather Advisory Committee (CWAC). After some discussions, the CWAC in general agreed with using the same three climate scenarios for the Ninth Plan.

The Three Selected Climate Scenarios

The three selected RMJOC climate scenarios are: CanESM2_RCP85_**BCSD**_***VIC_P1***, designated as **A**; CCSM4_RCP85_**BCSD**_***VIC_P1***, designated as **C**; and CNRM-CM5_RCP85_**MACA**_***VIC_P3***, designated as **G**. All 19 RMJOC climate scenarios are listed in Table D - 3 in the previous section.

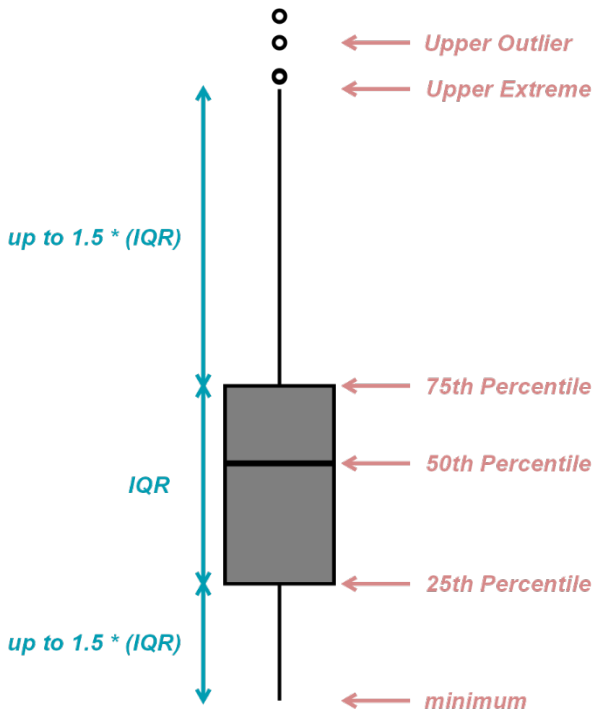
Methods for selecting scenarios A, C and G are described in detail in the "*Climate Change Scenario Selection Process"* supporting material of the previous 2021 Power Plan.[30] However, it should be noted that the selection methods utilized variables and simulation tool that have been replaced with different variables and a new simulation model in the current Ninth Plan. Therefore, to avoid any confusion, the "*Climate Change Scenario Selection Process"* supporting material of the previous 2021 Power Plan is referenced in a footnote but not presented here. Nevertheless, the methods developed previously for selecting A, C and G are still valid and are discussed briefly in this section.

In summary, the methods used were based on selecting a subset (of climate scenarios) whose four distributions of winter and summer hydro-generation, regional winter heating-degree-days (HDDs), and regional summer cooling-degree-days (CDDs), could be considered representative of the corresponding four distributions from the ensemble of all 19 scenarios. Specifically, winter is represented by the months December, January, and February, while summer is represented by months June, July, and August.

Comparisons of the four distributions are presented in box-and-whiskers plots (or boxplots for short). An illustration of a boxplot is presented in Figure D - 2 below. The boxplot allows for quantitative comparisons of distributional statistics such as the 25th, 50th (the median), and 75th percentiles. The grey box in Figure D - 2, which starts from the 25th percentile (at the bottom of the box) and ends at the 75th percentile (the top of the box), contains the central 50% of the population of the distribution. The length of the box is defined as the inter-quartile-range (IQR) and is used to delineate outliers (if any): those data that lie beyond one-and-a-half times the IQR from the box.

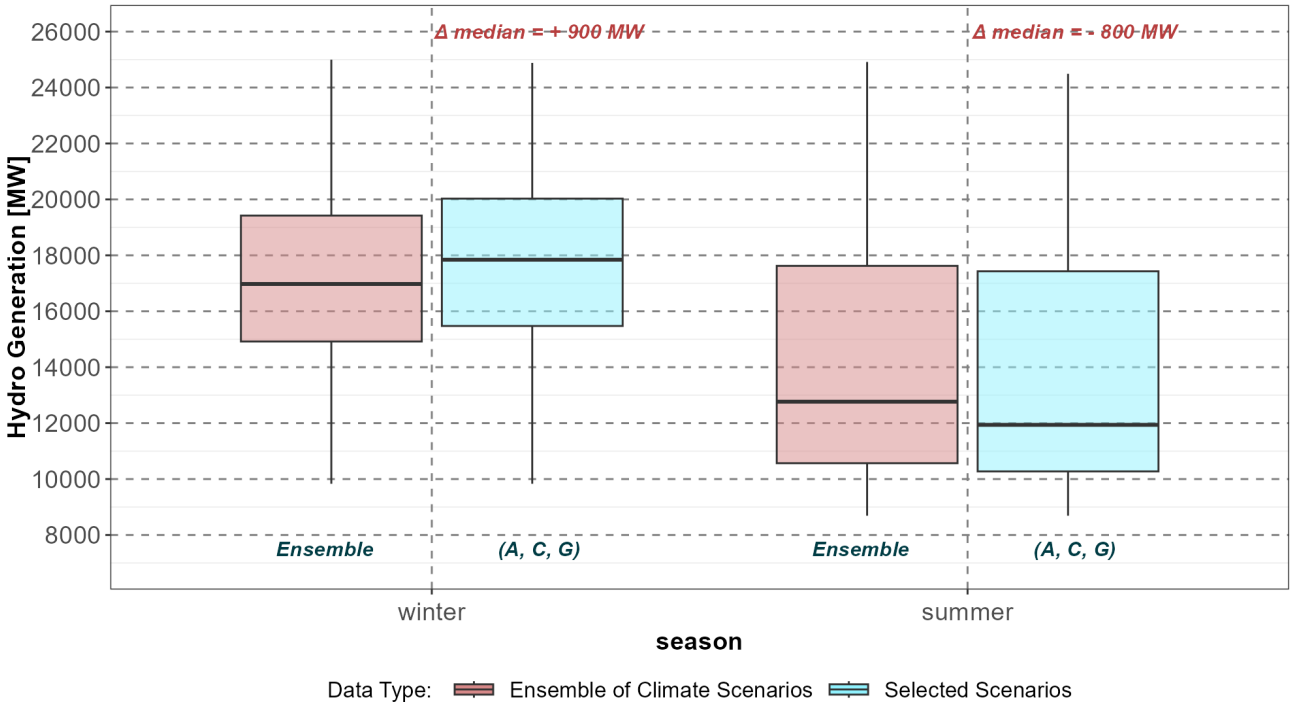
[30] https://www.nwcouncil.org/2021powerplan_climate-change-scenario-selection-process.

Figure D - 2: An Illustrative Example of Box and Whiskers Plot



First, comparisons of the winter and summer monthly average hydro-generation are presented as Figure D - 3 below.

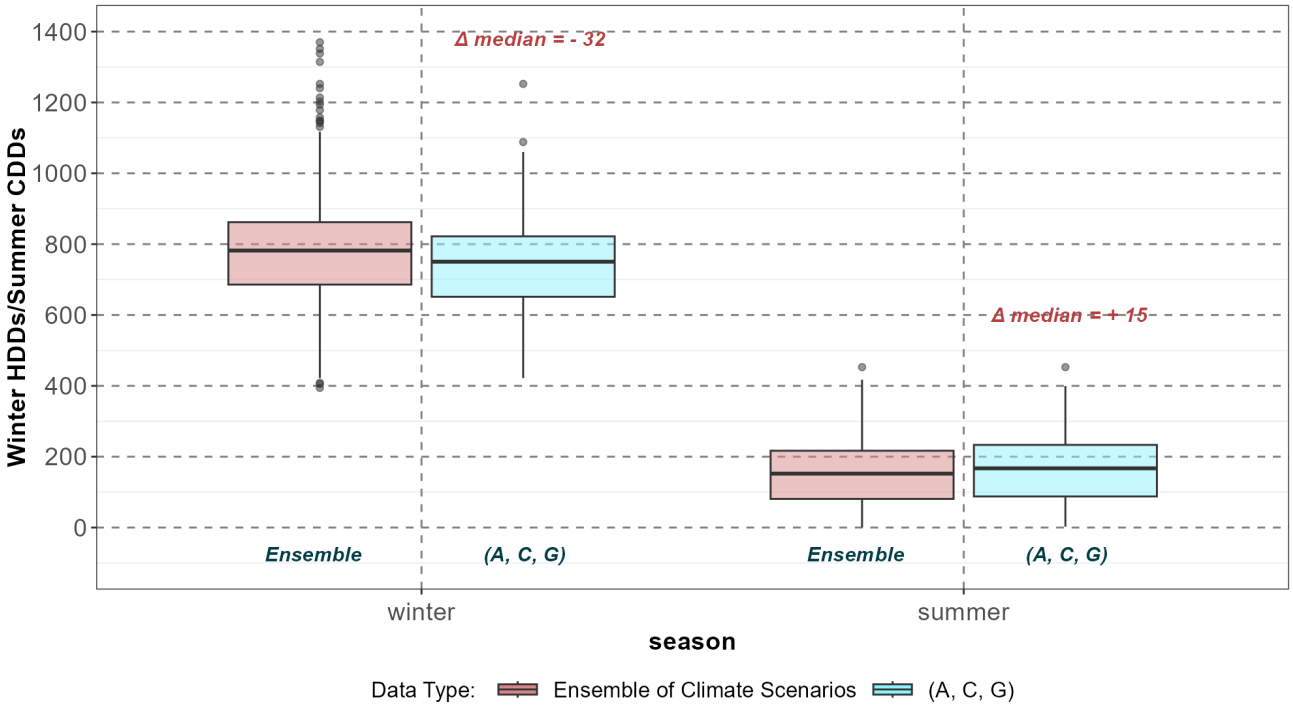
Figure D - 3: Comparison of Winter (left) and Summer (right) Hydro Generation Between Selected Scenarios and Ensemble



In Figure D - 3, average monthly hydro-generations of the ensemble distribution of all 19 climate scenarios are plotted in the light red boxplots while that of the distributions of the selected (A, C, G) scenarios are plotted in the light blue boxplots. Generations for the winter and summer seasons are plotted on the left side and right side, respectively. Furthermore, the difference between the median generations of the (A, C, G) distribution and the ensemble distribution is listed above the light blue boxplots. For winter hydro-generation, the light blue (A, C, G) distribution is *slightly higher* than the light red ensemble distribution, with the blue median being about 900 MW higher than the red median. In contrast, for summer hydro-generation, the blue (A, C, G) distribution is *slightly lower* than the red ensemble distribution, with the blue median being about 800 MW lower than the red median.

Next, comparisons of the winter Heating Degree-Days (HDDs) and summer Cooling Degree-Days (CDDs) are presented as Figure D - 4 below.

Figure D - 4: Comparison of Winter (left) and Summer (right) Degree-Days Between Selected Scenarios and Ensemble



In Figure D - 4, monthly degree-days (HDDs or CDDs) of the ensemble distribution of all 19 climate scenarios are plotted in the light red boxplots while those of the distribution of the selected (A, C, G) scenarios are plotted in the light blue boxplots. HDDs for winter and CDDs for summer are plotted on the left side and right side, respectively. Furthermore, the difference between the median degree-days of the (A, C, G) distribution and the ensemble distribution is listed above the blue boxplots. For winter HDDs, the blue (A, C, G) distribution is *slightly lower* than the red ensemble distribution, with the blue median being 32 degree-days lower than the orange median. In contrast, for summer CDDs, the blue (A, C, G) distribution is slightly higher than the red ensemble distribution, with the blue median being 15 degree-days higher than the orange median.

Therefore, the four distributions of the selected (A, C, G) scenarios are slightly different from the corresponding distributions of the ensemble, with opposite trends between winter and summer.

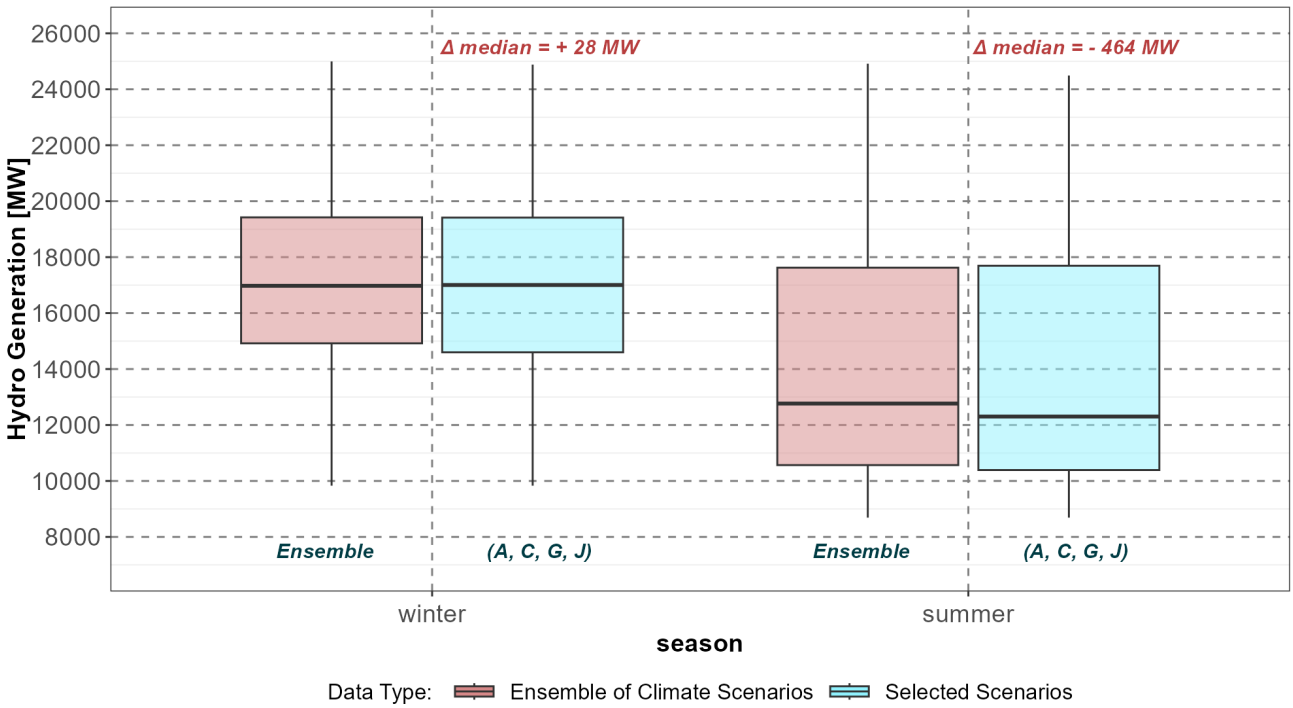
Selecting an Additional RMJOC Climate Scenario

Subsequent to the completion of the 2021 Power Plan, further analysis showed that by adding one more RMJOC climate scenario, namely **J**: GFDL_ESM2M_RCP85_**MACA**_***VIC_P1***, to the already selected A, C and G, the four distributions of the expanded subset (A, C, G, J) are much closer to the corresponding four distributions of the ensemble.

Specifically, in Figure D - 5, average monthly hydro-generations of the ensemble distribution of all 19 climate scenarios are plotted in the red boxplots while those of the distribution of the selected scenarios (A, C, G) plus scenario J are plotted in the blue boxplots. Generations for the winter and

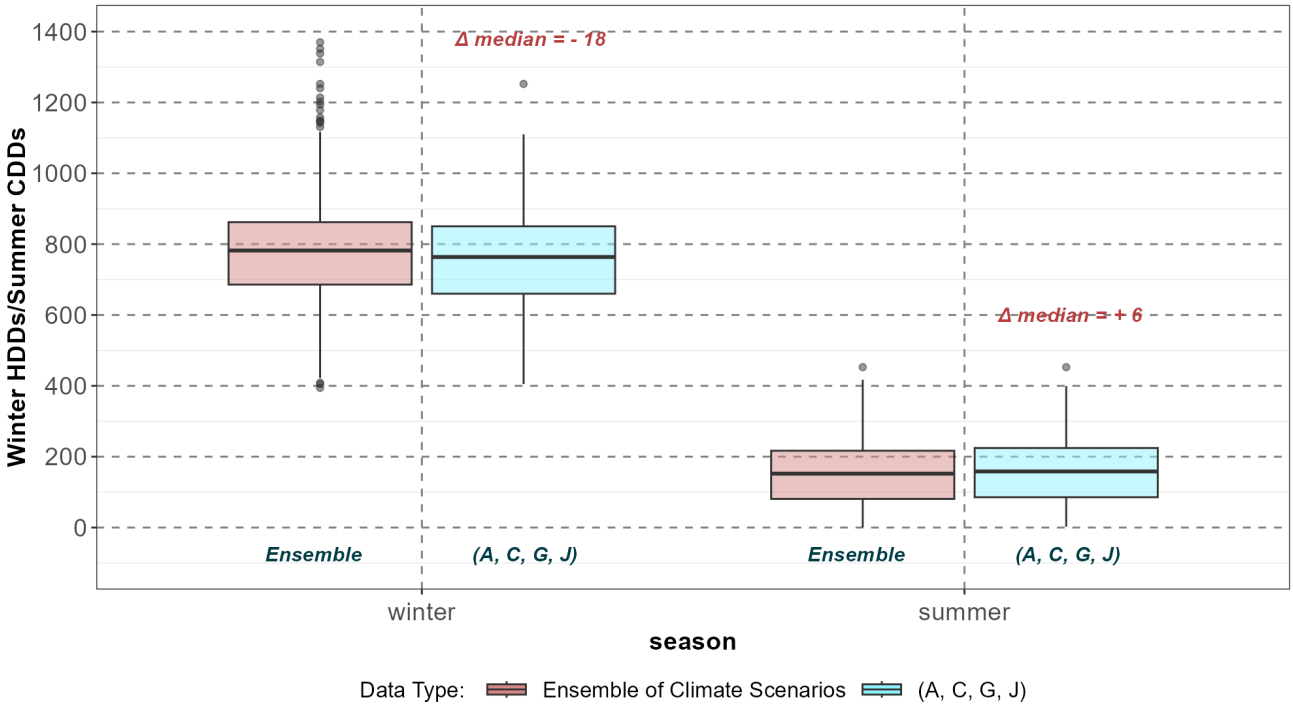
summer seasons are plotted on the left side and right side, respectively. Furthermore, the difference between the median generations of the (A, C, G, J) distribution and the ensemble distribution is listed above the blue boxplots. For winter hydro-generation, the blue (A, C, G, J) distribution is a very close match to the red ensemble distribution, with the blue median being only about 28 MW higher than the red median. Furthermore, for summer hydro-generation, the blue (A, C, G, J) distribution could also be considered a very close match to the red ensemble distribution, despite the blue median being about 464 MW lower than the orange median.

Figure D - 5: Comparison of Winter (left) and Summer (right) Hydro-Generation Between Selected Scenarios Plus Scenario J vs Ensemble



Finally, comparisons of the winter HDDs and summer CDDs are presented in Figure D - 6 below.

Figure D - 6: Comparison of Winter (left) and Summer (right) Degree-Days Between the Selected Scenarios Plus J vs the Ensemble



In Figure D - 6, the monthly degree-days (HDDs or CDDs) of the ensemble distribution of all 19 climate scenarios are plotted in the red boxplots while those of the distribution of the selected scenarios (A, C, G) plus scenario J are plotted in the blue boxplots. HDDs for winter and CDDs for summer are plotted on the left side and right side, respectively. Furthermore, the difference between the median degree-days of the (A, C, G, J) distribution and the ensemble distribution is listed above the blue boxplots. For winter HDDs, the blue (A, C, G, J) distribution is very close to the red ensemble distribution, with the blue median being only 18 degree-days lower than the red median. Moreover, for summer CDDs, the blue (A, C, G, J) distribution is also very close to the red ensemble distribution, where the blue median is only 6 degree-days higher than the red median.

Therefore, compared to the original selected (A, C, G) subset, the four distributions of the adding J are much closer to the corresponding distributions of the ensemble. Thus, adding J would result in a more representative of the ensemble.

Staying With the Original Three Selected Climate Scenarios

The Council considered using climate data by adding in scenario J for the Ninth Plan due to the final suite being more representative of the entire ensemble of 19 RMJOC climate scenarios. However, scenario J seems to have opposite climate trends in winter.

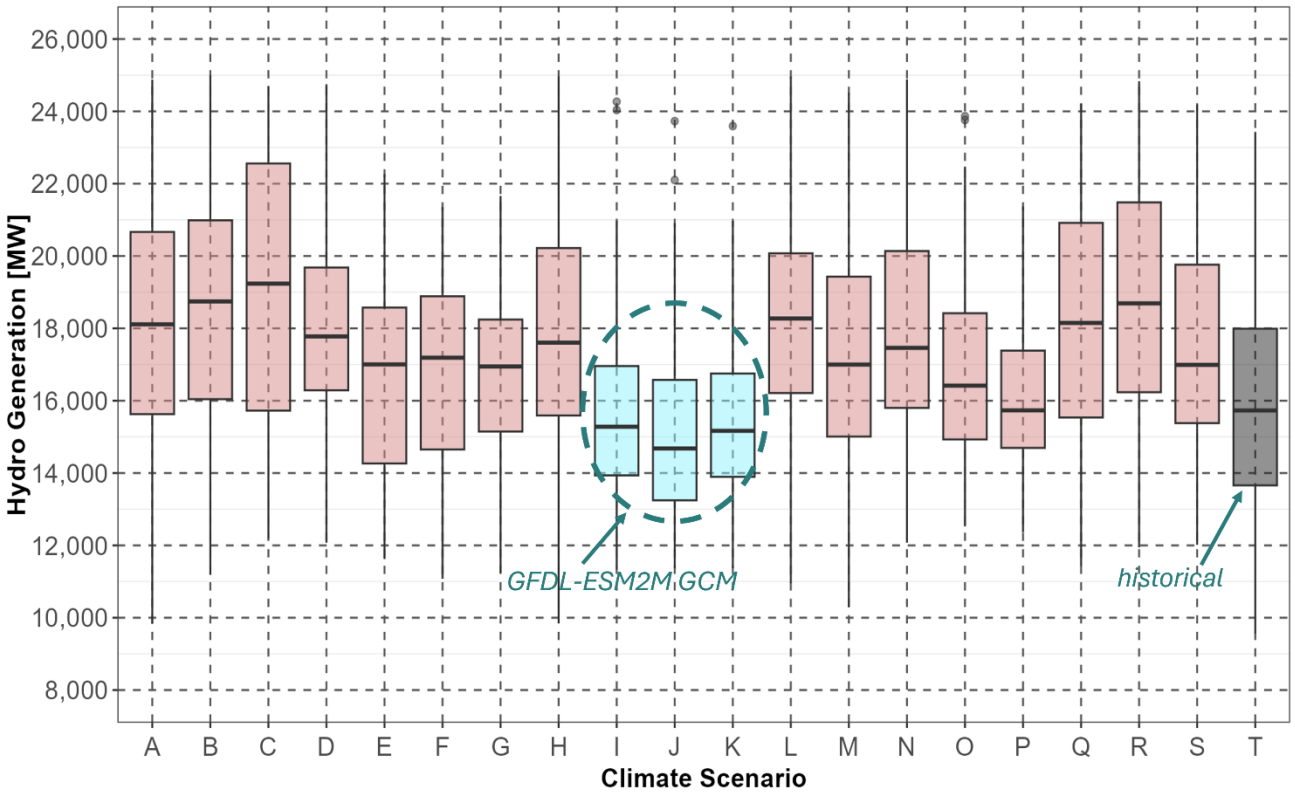
First, according to the RMJOC report,[31] the GFDL-ESM2M GCM, from which climate scenario J is derived, is forecasted to have higher winter temperature (throughout the region) and higher precipitation (over most of the region) in the future time period from 2020 to 2049 than in the historical time period, from 1970 to 1999. Since having higher winter temperature and precipitation over most of the region would in general lead to higher winter streamflows, then for scenario J, the future time period should have higher winter hydro-generation than the historical time period.

But as show in Figure D - 7, it is the opposite trend. The boxplots in Figure D - 7 are the winter hydro-generation of the ensemble distribution of all 19 climate scenarios (the orange boxplot) in Figure D - 5 disaggregated into its 19 component scenarios separately. The 19 scenarios are represented by the letters A to S along the x-axis. Since the hydro-generations were calculated using climate model streamflows that were adjusted using the historical irrigation depletions of 2008, then for a fair comparison, historical winter hydro-generation is also calculated using the 2010 Level historical modified flows (80 water-years from 1929 to 2008) which were adjusted with the same irrigation depletions of 2008. The historical winter hydro-generation is plotted in the gray boxplot on the right side, represented as scenario "T."

Therefore, Figure D - 7 shows that winter hydro-generation of climate scenario J, plotted in one of the three light blue boxplots inside the dashed green oval, is lower than the historical winter hydro-generation plotted in the gray boxplot for scenario "T." This is opposite to the expected higher winter generation discussed previously.

[31] See Figures 28, 29 and 35 in "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

Figure D - 7: Winter Hydro-Generations for the 19 Climate Scenarios and Historical



Furthermore, climate scenarios I, J and K, represented by the three light blue boxplots, are all derived from the GFDL-ESM2M GCM (see Table D - 3), and their winter hydro-generations are all below the historical winter hydro-generation in the gray boxplot.

In addition, the remaining 16 climate scenarios, A to H, and L to S (seeTable D - 3), represented by the 16 light red boxplots in Figure D - 7, are derived from eight of the remaining nine GCMs (where the HadGEM2-ES GCM in Table D - 1 has been excluded). It could be seen that winter hydro-generations of (the 16 climate scenarios derived from) these eight GCMs are higher than the historical winter hydro-generation (in the gray boxplot). This trend is consistent with their warmer winter temperature and higher winter precipitation as presented in the RMJOC report.[32]

The opposite trends of future winter hydro-generation (which was presented to the CWAC[33]) suggest that scenario J, or more generally, climate scenarios derived from the GFDL-ESM2M GCM, could be significantly underestimating historical streamflows. However, a better understanding would require

[32] See Figures 28, 29 and 35 in "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

[33] Climate and Weather Advisory Committee meeting on 7/15/2024: https://www.nwcouncil.org/meeting/climate-and-weather-advisory-comm-kick-off-2024-07-15.

further systematic analysis by climate scientists. Therefore, even though including scenario J would make the suite more representative of the ensemble of 19 RMJOC scenarios, the Council decided it was prudent to exclude this scenario for the Ninth Plan due to its anomalous lower winter hydro-generation. Council staff proposed to stay with the original three-scenario subset (A, C, G) during meetings of the CWAC.[34] While some members of the CWAC supported including the additional scenario J to increase diversity of the climate data, ultimately there was no objection to the Council using climate data from the three-scenario subset (A, C, G).

The Climate Scenario Years Used in the Ninth Power Plan

Data in the RMJOC climate scenarios are of daily time-step and start on 1/1/1950 and end on 12/31/2099, totaling 150 years of data. For analysis, RMJOC staff chose time periods spanning 30 years. For example, the historical period is the 30-year span from 1970 to 1999, and is referred to as the 1980s for simplicity; a near-future period is the 30-year span from 2020 to 2049, and is called the 2030s; and finally, a distant future period spans the 30-years period from 2060 to 2089, called the 2070s.[35]

For modeling hydro-operations under the influence of climate scenario data, the RMJOC also used the same three sets of 30-year time-periods, the 1980s, the 2030s, and the 2070s. For those three sets of time-periods, they also developed hydro-regulation rule-curves, such a flood control, and operation constraints for the various hydro-projects in their hydro-regulation models.[36] The RMJOC shared with the Council the climate scenario data (from 1950 to 2099) and the associated hydro-regulation rule curves and constraints for the 2030s and the 2070s.

As decided by the Council, the Ninth Plan is developed for the 20-years from 2027 to 2046, which conveniently can draw upon as inputs the 150 years of climate scenario data, and the RMJOC hydro-regulation rule curves and constraints for the 2030s (from 2020 to 2049). Thus, during meetings of the CWAC, the staff proposed using climate scenario data for the 2030s set of climate scenario years and the RMJOC 2030s set of rule-curves and constraints, since they have been incorporated into various Council simulation models.[37] A few committee members expressed their preference of using a few more climate scenario years beyond 2049 to capture stronger climate trends, which the Council staff

[34] Climate and Weather Advisory Committee meeting on 8/1/2024: https://www.nwcouncil.org/meeting/climate-and-weather-and-conservation-resources-adv-comm-combined-meeting-2024-08-21, and on 12/4/2024: https://www.nwcouncil.org/meeting/climate-and-weather-advisory-committee-2024-12-04.

[35] *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

[36] "Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part II: Columbia River Reservoir Regulation and Operations—Modeling and Analyses" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-ll.PDF.

[37] Climate and Weather Advisory Committee meetings on 7/15/2024: https://www.nwcouncil.org/meeting/climate-and-weather-advisory-comm-kick-off-2024-07-15, and on 8/1/2024: https://www.nwcouncil.org/calendar/climate-and-weather-advisory-committee-2024-08-01.

also shares. However, the hydro-regulation rule curves and operation constraints for a few years beyond 2049 are not readily available. Therefore, the Council decided to use the available data from the 2030s climate scenario years (from 2020 to 2049) only.

Another consideration for incorporating climate data into the Council's models is the sampling method for the climate scenario years for temperature, water, wind, and solar data. More specifically, because temperature and precipitation output (both sets of data are used to calculate streamflow) from the GCMs are not independent, the temperature year and water year selected for each simulation run must be the same climate year. Mixing climate scenario years for temperature and precipitation could lead to unlikely occurrences.

For a rather simplified example, at a specific location in the region, if temperatures were mostly above freezing during fall and winter for a particular climate year, then most of the precipitation during that period would fall as rain, resulting in higher streamflow but depositing a smaller snowpack in the mountains. Then during spring and early summer, streamflow would be lower due to contribution from a smaller snowpack.

Alternatively, if fall and winter temperatures were mostly below freezing, then precipitation would mostly fall as snow, resulting in lower streamflow but creating a larger snowpack. Then spring and early summer of that climate year should see higher streamflow due to contribution from the larger snowpack.

These two simple examples illustrate that even with the same amount of seasonal precipitation, temperature can have a significant influence on the timing and magnitude of streamflow. Thus, pairing temperature and streamflow patterns from two different climate scenario years could lead to unlikely situations such as having freezing temperatures during winter (from one climate year) but with winter precipitation falling as rain (from another climate year) that leads to higher streamflow and smaller snowpack.

In addition to using the same climate year for temperature and water in a simulation run, it is important to also use the same climate year for wind and solar data. The reason for doing so is that all the climate data should represent the same weather systems simulated in a GCM. In other words, the weather systems that bring temperatures and precipitations into a region also carry along the wind and cloud cover (which influences solar radiation). Using the same climate scenario years for the four types of data enables them to be considered temporally coincident, and the impact of weather on operations of the power system can be modeled consistently.

The following sections provide a more comprehensive description of the climate model data and methods to adapt them for the Ninth Power Plan.

In-Region Climate Scenario Data

There are four types of climate scenario data used in the Power Plan: streamflow, temperature, wind generation, and solar generation. They are analyzed and presented in the following sections.

As discussed previously, the climate scenario streamflow data were produced by the RMJOC, and they are used directly (among other data) in the Council's resource adequacy model and capital expansion model, GENESYS and OptGen, respectively, to simulate operations and generations of the hydro system. The streamflow data are daily averages and located at 74 hydro-projects and gauging stations simulated in both models.[38] Since there are many years of corresponding historical streamflow data available, comparisons of historical data to climate model data will enable discovery of climate trends, if any. In addition, since hydro-generation is a major component of the regional power system, it is also of interest to analyze for very high and very low streamflows.

Similar to the climate scenario streamflow data, the climate temperature data were also produced by the RMJOC, and they are used, among other data, in the Council's load forecasting model, developed by Itron,[39] to produce loads at the 13 balancing authorities (BAs) in the region. The temperature data are daily minima and maxima and located at 26 locations throughout the region. Analogous to the historical streamflow data, there are many years of corresponding historical temperature data available and comparing them with climate temperature data will allow discovery of climate trends, if any. Moreover, since very high or very low temperatures lead to very high loads, and thus it is important to analyze frequencies and magnitudes of the extreme temperatures.

The remaining two climate scenario data, wind speed and solar radiation, are not included in the RMJOC data set. Fortunately, identical or very similar climate scenario wind and solar data are available at the Climatology Lab.[40]

Five representative locations were selected to model wind fleet generation for the region, and their corresponding climate wind speed data were downloaded from the Climatology Lab. The data are daily averages which undergo further calculations to become hourly wind generations and thus inputs in the Council's models. Some calculations include bias-corrections of the data in historical years to replicate statistical properties such as, the correlations between historical wind and historical temperature data, and the monthly distributions of historical wind data. The methodologies are discussed in detail in a following section.

Finally, three representative locations were selected to model solar generation for the region, and their corresponding climate solar radiation data are also available from the Climatology Lab. However, during a meeting of the CWAC, some climate scientists expressed concern that the original GCMs might not be able to model cloud cover (and therefore solar radiation) accurately over small geographical areas due to the coarse spatial grids used in the GCMs. Thus, alternative methods were developed to model solar generation, and details of which are presented in a subsequent section.

[38] In the Council's models, there are a few hydro-projects classified as "small or independent hydro" that do not use climate scenario streamflows. They are modeled as renewable resources with historical monthly generation shapes. On average, their aggregate generation is about 1,100 aMW.
[39] See Appendix F – Electricity Demand Forecast in the Ninth Power Plan for more details.
[40] Climatology Lab: https://www.climatologylab.org/maca.html.

Many GCMs have systematic errors or biases in their output which are differences between the output and some baseline values, for example, a set of historical observations or widely accepted output of climate and weather models. The biases are often due to coarse resolution used and simplified physical processes assumed in the GCMs. Therefore, to enable more realistic and thus more believable GCM output, they undergo bias-corrections[41,42] to align themselves more closely with historical observations or widely accepted data. For streamflow and temperature data from the RMJOC climate scenarios, climate scientists and RMJOC staff have already performed appropriate bias-corrections.[43] For climate scenario wind and solar data downloaded from other sources, they also undergo bias-corrections which are discussed in more detail in subsequent sections.

Trends in Historical and Climate Scenario Streamflows

As discussed above, the Council has decided to use data from three of the 19 climate scenarios developed by the RMJOC for the Ninth Plan analysis. In this section, analyses of both historical and climate model streamflows are presented which show the climate trends that will influence the generation portfolios developed for the Power Plan.

Trends in Historical Streamflows

The RMJOC in 2013 began the development of climate scenario data, including modified streamflows. In that process, the RMJOC used the 2010 Level Modified Streamflow data set, which are historical streamflows that would have been observed if irrigation depletions (as of year 2008) existed in the past and if the effects of river regulation were removed (except at the upper Snake, Deschutes, and Yakima basins, where current upstream reservoir regulation practices are included).[44] In this section, the historical 2010 Level Modified Streamflows (referred henceforth as "historical streamflows" for simplicity) are analyzed for possible climate trends.

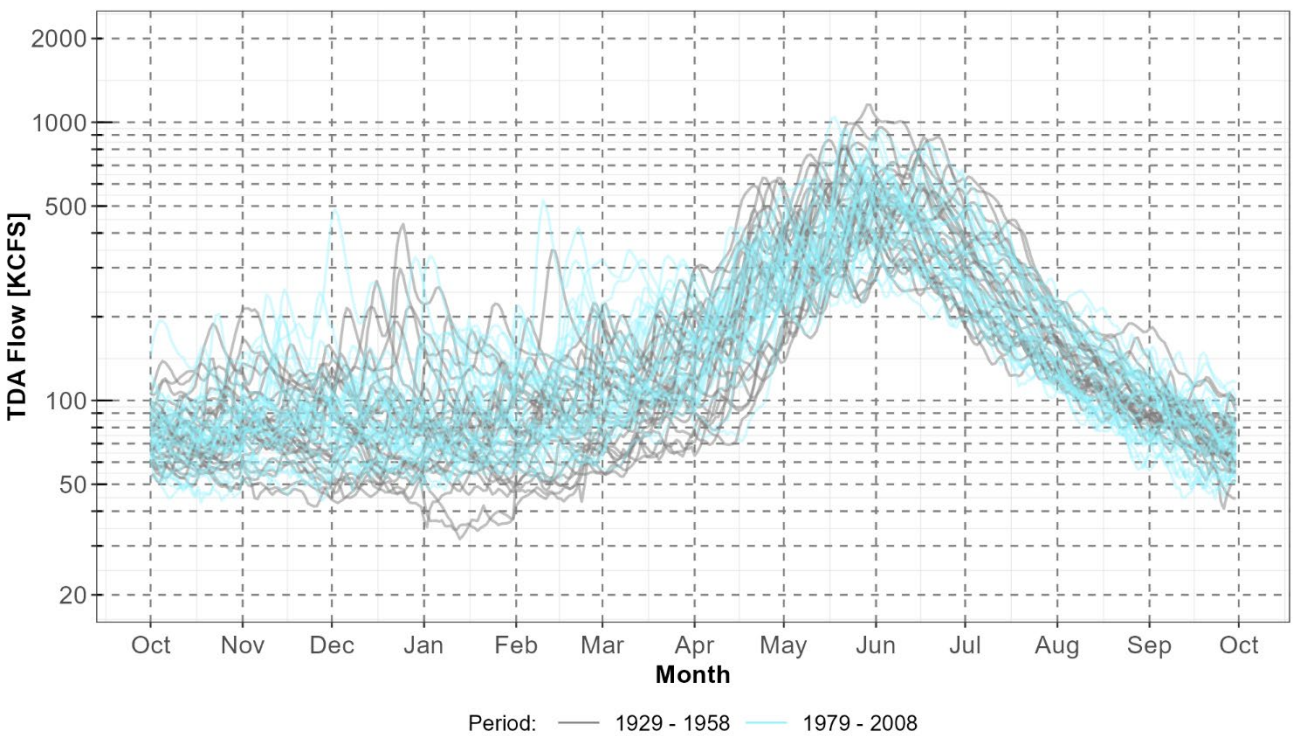
The historical streamflow set consists of 80 water-years of daily streamflows from 1929 to 2008 at many sites of interest throughout the Columbia River Basin, including at all hydro projects modeled in GENESYS. By definition, a water-year begins in October and ends in September of the following year. For example, the 1987 water-year begins on October 1, 1986, and ends on September 30, 1987. For the same water-year, the annual volume and monthly pattern of streamflow measured at stream gauging stations in different sub-basins, for example, Mica and The Dalles (TDA), can be vastly different. Nevertheless, streamflow at TDA, which is located near the mouth of the Columbia River, is

[41] https://glisa.umich.edu/wp-content/uploads/2021/03/Global-Climate-Model-Bias-and-Bias-Correction.pdf .
[42] https://climate.copernicus.eu/sites/default/files/2021-01/infosheet7.pdf.
[43] *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.
[44]See https://www.oregon.gov/owrd/WRDReports/appendix_d_flow-data-set-res-sim-analysis.pdf for more details of 2010 Level Modified Streamflows. However, in 2020, the Bonneville Power Administration published a new modified streamflow data: the *2020 Level Modified Streamflows*. See https://www.bpa.gov/-/media/Aep/power/historical-streamflow-reports/2020-level-modified-streamflow-seasonal-volumes-and-statistics.pdf.

commonly used to classify a water-year (i.e., a critical or dry year, an average year, or a wet year) for the entire Columbia River Basin.

Because the historical streamflow record spans 80 years, it is worthwhile to investigate whether they have fundamentally changed over time, that is, if trends in the volume and pattern of streamflow are observable. Thus, in Figure D - 8, TDA streamflows for the first 30 water-years, from 1929 to 1958 (plotted in gray), are compared with those for the last 30 water-years (plotted in light blue), from 1979 to 2008. With respect to 2010 Level Modified Streamflows, the 30 years from 1929 to 1958 are the first 30 years, while the 30 years from 1979 to 2008 are the last 30 years. For simplicity, in subsequent sections, streamflows for the two sets of 30 years will be referred to as "first 30 years" and "last 30 years," respectively.

Figure D - 8: Comparison of The Dalles Daily Streamflows for Two Historical Time Periods



On the x-axis are the months from October to the next September for a water year. On the y-axis are the TDA flows in thousand cubic feet per second (or KCFS).[45] The plots in Figure D - 8 are called trace plots because streamflows for the 60 water-years are plotted separately in 60 traces. Furthermore, the traces are plotted in log scale so that visual comparisons are easier for streamflows with both large and small magnitudes. However, visual comparison of the 60 traces remains difficult because of the high amount of overlap. Nevertheless, the trace plots are still useful since they do allow for an

[45] The same axes are used in the following series of figures comparing different streamflows at TDA.

easy visual scan for outliers, that is, streamflows with significantly different monthly magnitudes and shapes.

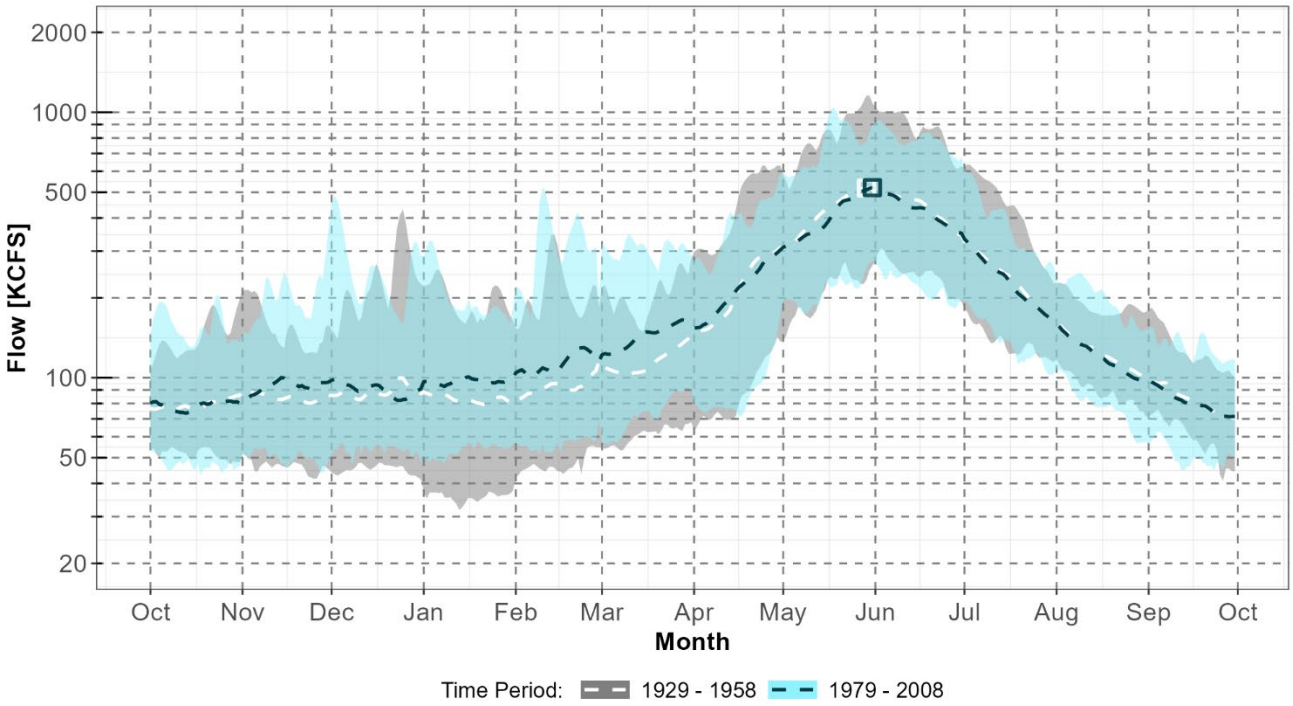
The streamflow traces for the first 30 years (in gray curves) and the last 30 years (in light blue curves) look similar at a glance, except for two gray traces, representing water-years 1930 and 1937, which have very low streamflows in January. These are the lowest historical streamflows. Furthermore, there is a hint that flows for the last 30 years (in light blue curves) might be slightly higher from January to April.

In contrast, there is one gray trace representing 1948 that have very high flows, at or greater than 1,000 KCFS, from late May to early June. After 1948, there were three other years, 1972, 1974 (both not plotted due to being outside the two selected historical time periods) and 1997 where the flows were similarly very high for a few days in mid-May (plotted in a blue trace). These are the highest historical streamflows.

Beside the trace plots in Figure D - 8, two other types of plots are presented to compare TDA streamflows between the historical first 30 years and last 30 years.

First, Figure D - 9 shows the envelope plots, in which streamflows for the first 30 years are represented in the gray area while those for the last 30 years are represented in the light blue area. For each set of streamflows, the envelope data are obtained by extracting the maximum and minimum streamflow for each day over all 30 years. In addition to the envelope plots, the average daily streamflows are also plotted in Figure D - 9, the white dashed curve for the first 30 years and the dark blue dashed curve for the last 30 years.

Figure D - 9: Comparison of Maximum, Minimum, and Average TDA Daily Streamflows for Two Historical Time Periods



The envelope plots in Figure D - 9 show less data than the trace plots in Figure D - 8, but they allow for easier comparisons of the monthly shapes of the maxima and minima. For example, for most days from November to mid-April, streamflows for the last 30 years (in the light blue area) have higher maxima and minima than those for the first 30 years (in the gray area). Moreover, comparing the two dashed curves shows that, for most days from November to mid-April, the average streamflow is also higher for the last 30 years (in blue) than for the first 30 years (in white). For example, for January 15, the difference is 18.7 KCFS higher or +23% (relative to the average streamflow for the first 30 years).

Another interesting observation is the spring maximum of the TDA average streamflow. In Figure D - 9, the spring maxima for the averages are plotted as squares, in white for the first 30 years and in dark blue for the last 30 years. The spring maximum for the historical last 30 years occurs one day later than the maximum for the first 30 years. The difference is however too small from which to draw any conclusion about temporal shifts between the two historical periods.

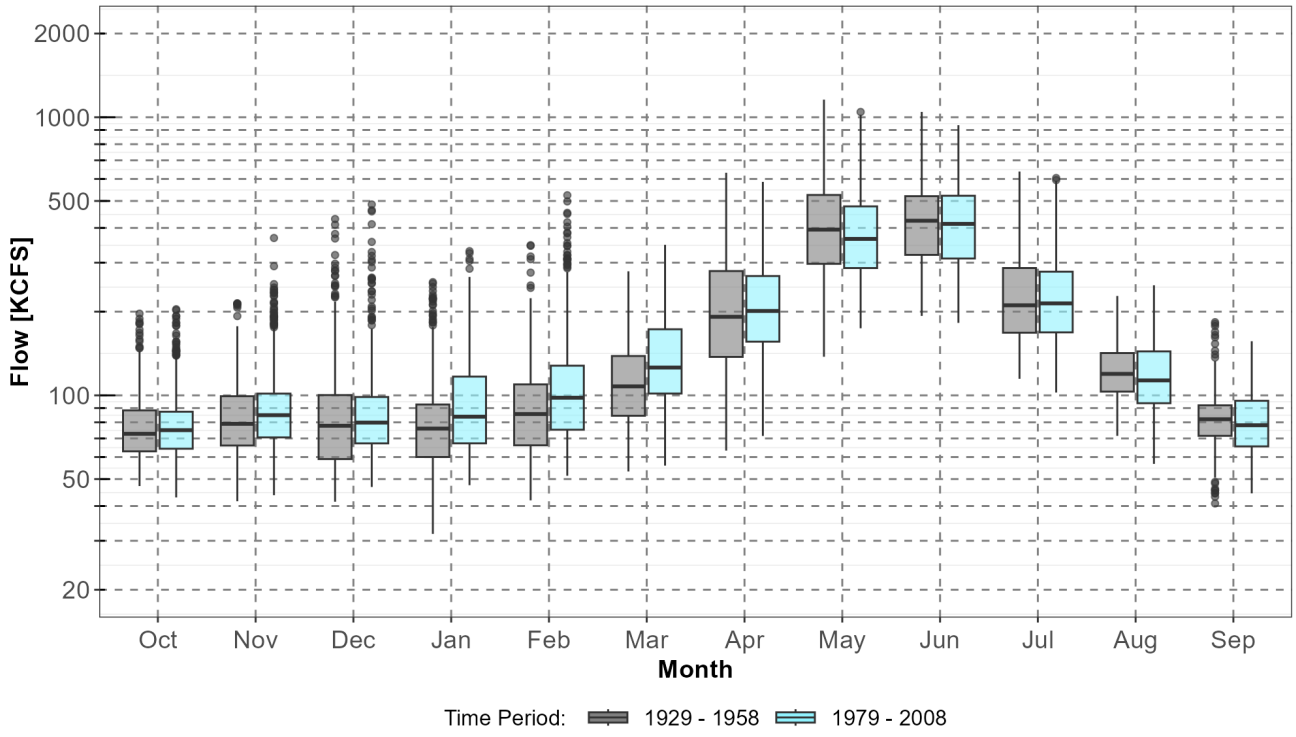
In summary, between historical water-years 1929 to 1958 and 1979 to 2008, there appears to be a trend for higher flows at TDA from November to April. This trend is consistent with a portion of the climate change signal analyzed in RMJOC report I.[46] (However, the RMJOC climate trend of lower flows at TDA for the summer months is not present for the two sets of historical data. In addition, the

[46] See Figure 49 in "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

trend of an earlier temporal shift in the spring maximum streamflow is also not evident. Therefore, analysis of Figure D - 9suggests that a portion of climate change impacts, namely the higher November through April streamflows, is already present in the historical streamflow data

Next, monthly boxplots of the same data are presented in Figure D - 10, which compares the monthly distributions of TDA daily streamflows between the historical first 30 years, from 1929 to 1958 (in gray), and the last 30 years, from 1979 to 2008 (in light blue).

Figure D - 10: Comparison of Monthly Distributions of TDA Daily Streamflows



The side-by-side boxplot statistics allow for easy quantitative comparisons of the monthly distributions for the two sets of historical streamflows. However, comparisons of monthly shapes in terms of boxplots are more difficult than those comparisons in terms of envelope plots as presented in Figure D - 9.

In Figure D - 10, for November to March, most of the boxplot statistics (outliers, whiskers, median, 25th and 75th percentiles) show that streamflow is generally higher for the last 30 years. Furthermore, by comparing just the median, the higher streamflow for the last 30 years takes place over a longer period, from October to April. As for the summer months from June to August, the monthly distributions for both historical streamflow sets are similar.

Thus, the plots in Figure D - 10 support the observation in Figure D - 9 that the RMJOC projected climate-driven trend of increasing flows for October to March (or April) is present in the historical data. On the other hand, the trend of decreasing flows for summer months is not evident in the historical data.

Since the climate scenario modified flows were calculated using irrigation depletions of year 2008, then for consistency, in subsequent sections, they will be compared to the historical 2010 Level modified flows which were calculated using the same irrigation depletions of 2008.

Subsequent to the completion of the RMJOC climate scenario data in 2018, a newer historical streamflow data set became available in 2020, the 2020 Level Modified Streamflows which incorporated the effects of irrigation depletions of year 2018. For comparisons to climate scenario streamflows, using the 2010 Level Modified Streamflows is appropriate since both climate scenario and the 2010 modified streamflows have the effects of the same 2008 irrigation depletions. Nevertheless, it is still of interest to analyze for climate trends in the 2020 modified flows to compare and check for consistency with climate trends in the 2010 modified flows just analyzed in this section.

The resulting analysis of the more recent 2020 Level modified TDA flows (not shown here) also supports a similar trend of higher flows for the last 30 years (now from 1989 to 2018) for November to April. However, the 2020 Level modified flows also suggest the climate-driven trend of decreasing flows for the summer months, from June to September, which was not evident in the 2010 Level flows. Furthermore, for the 2020 Level flows, the average TDA flow for the last 30 years has a spring maximum occurring 8 days later than that for the first 30 years, in contrast to occurring just 1 day later for the 2010 Level flows as previously presented.

Trends in Climate Scenario Streamflows

For climate scenarios A, C and G, their TDA modified streamflows are also analyzed using the three types of plot: the trace, the envelope and the boxplot presented previously in Figure D - 8 to Figure D - 10, respectively. The analyses involve comparing historical streamflow for the last 30 years, from 1979 to 2008, with the three sets of climate scenario streamflows for the 30 years from 2020 to 2049. For simplicity, those 30 years from 2020 to 2049 will be referred to as the "next 30 years."[47] Similar analyses have already been done in an RMJOC report[48] for the No Regulation – No Irrigation (NRNI) streamflows, for a slightly different set of historical water-years and presented in different types of plots. Nevertheless, it is expected that climate trends for the TDA streamflow analyzed in the following sections are consistent with those presented in the RMJOC report.[48]

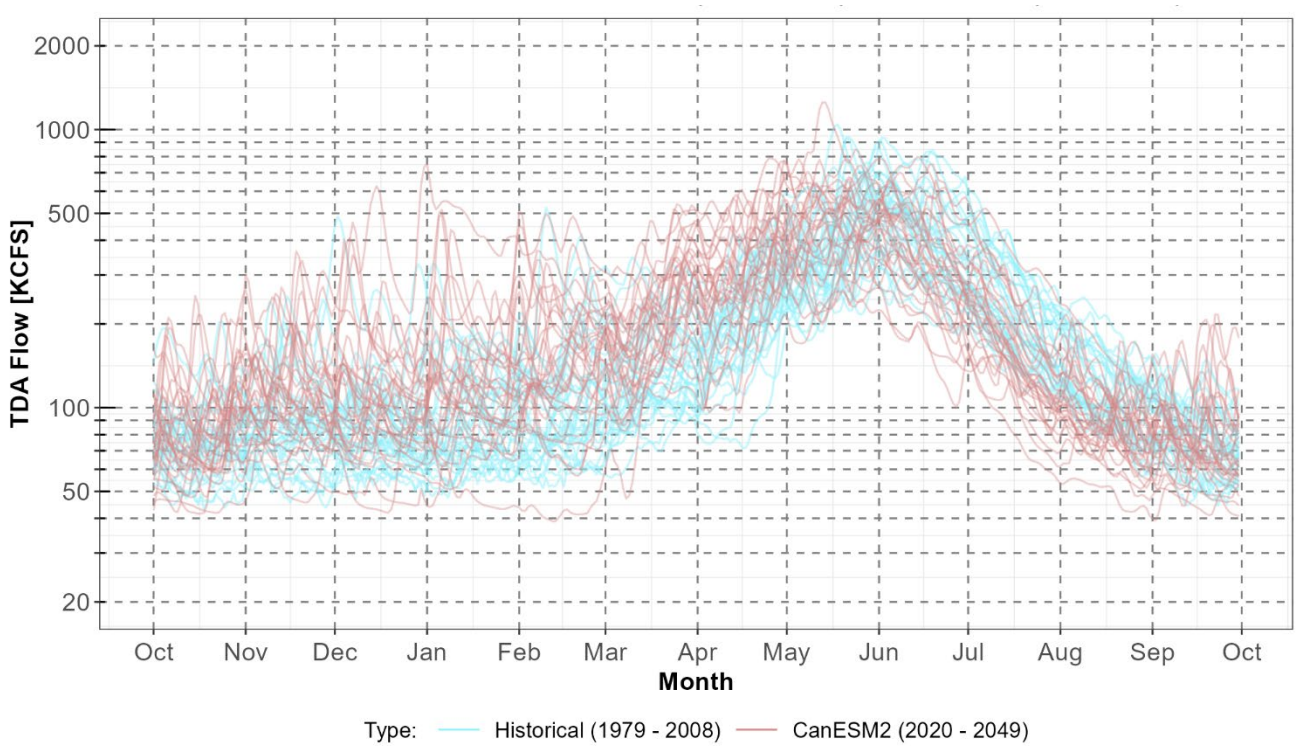
Climate Scenario A

In Figure D - 11, the 30 light blue traces are the historical daily TDA flows from 1979 to 2008 and the 30 light red traces are climate scenario A (CanESM2 GCM) daily TDA flows from 2020 to 2049.

[47] Referring 2020 to 2049 as the "next 30 years" was more accurate when this section was written during development of the previous 2021 Power Plan that started in 2019.

[48] *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

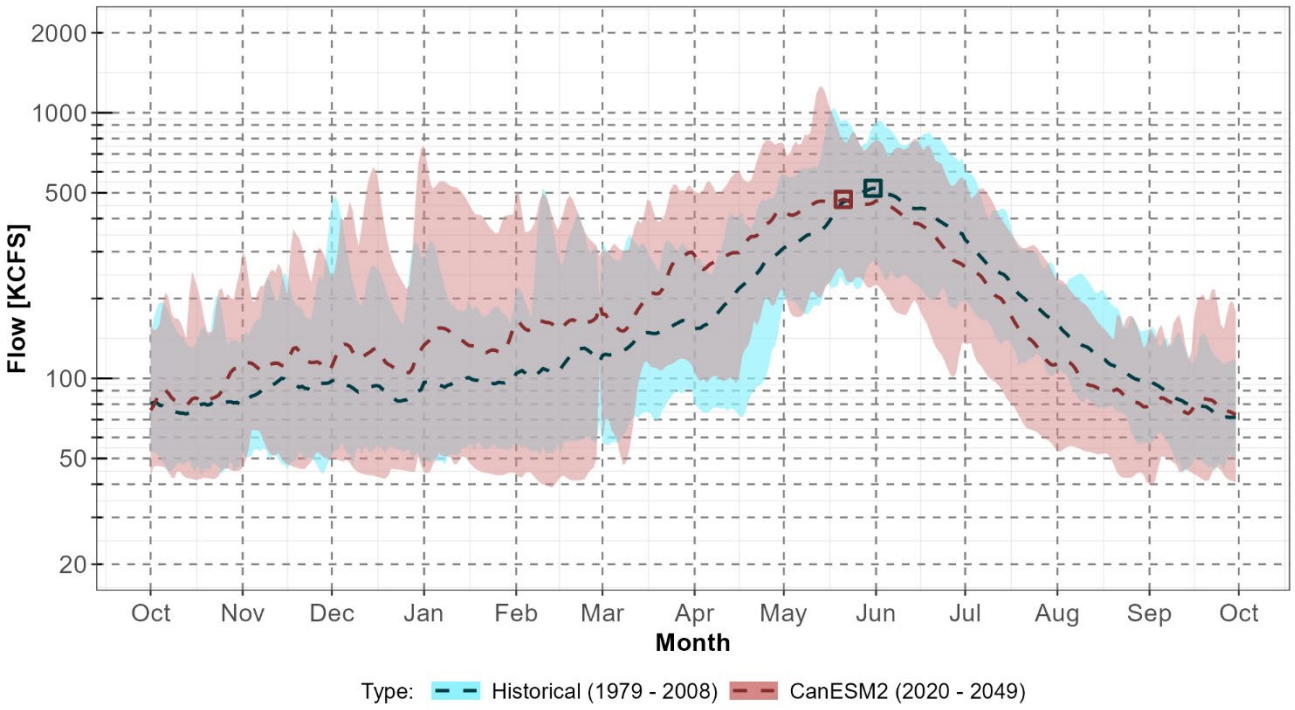
Figure D - 11: Comparison of Historical vs Climate Scenario A Daily Streamflows at TDA



It is easy to see that as a distribution, from October to April, the 30 Scenario A climate traces are generally higher than the 30 historical traces. However, there are still one or two climate traces below the minimum historical traces for December to March. On the other hand, for the three summer months from June to August, the distribution of Scenario A traces is lower than the distribution of the historical traces. It should be noted that there are seven days in mid-May that the Scenario A climate trace representing water-year 2047 has flows at or higher than 1,000 KCFS.

Next, the envelope plots and the averages for the climate and historical traces in Figure D - 11 are presented in Figure D - 12, along with the squares indicating the spring maxima of the 30-year averages.

Figure D - 12: Comparison of Historical and Climate Scenario A Streamflows



The envelope plots and averages in Figure D - 12 show that for most days from October to mid-May, the climate scenario streamflows, represented by the light red area and dark red dashed curve, are generally higher than the historical (last 30 years) flows, represented by the light-blue area and dark blue dashed curve. In contrast, for the summer months June to August, the climate scenario streamflows are generally lower than the historical flows.

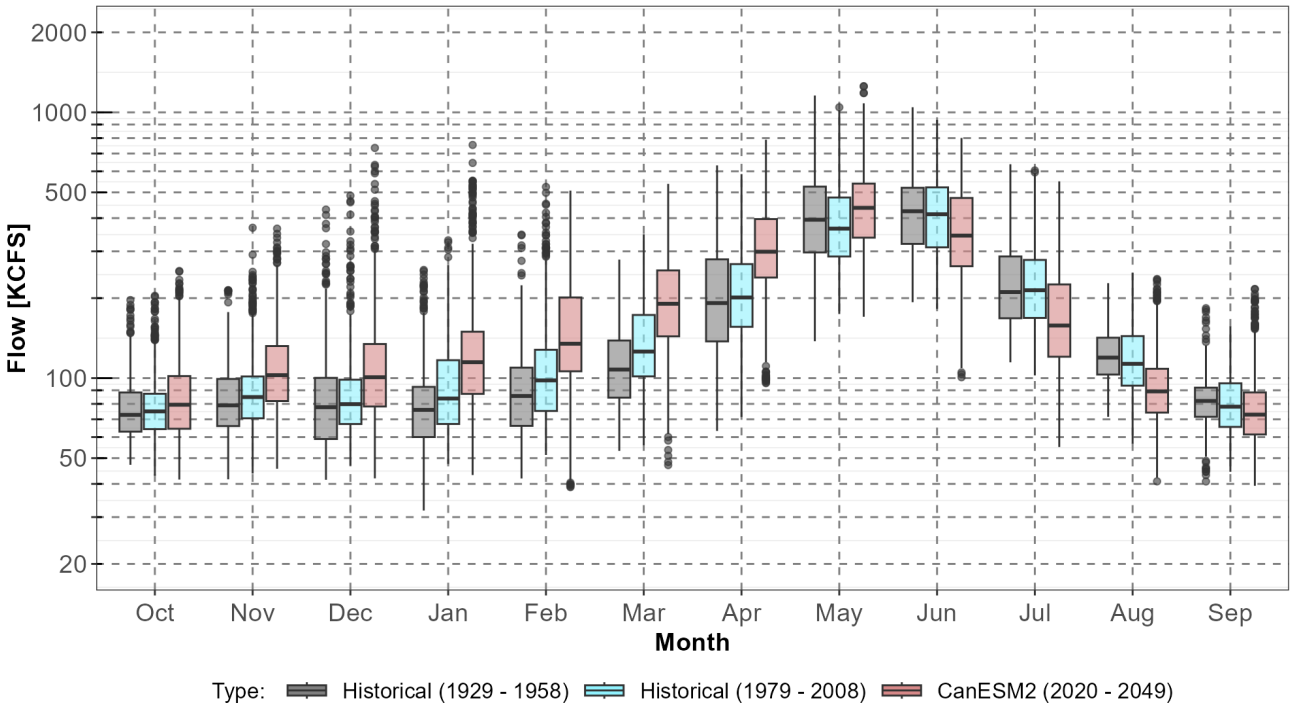
Furthermore, the spring maxima of the average streamflows in Figure D - 12, plotted in the dark blue square for the historical data and dark red square for Scenario A data, show the climate Scenario A maximum occurring 10 days earlier, on May 21. It is worthwhile to analyze this shift in more details as follows. The average streamflow for scenario A in the red dashed curve has contributions from all 30 climate (light red) traces in Figure D - 11. There are 16 (among 30) climate traces where the dates of their spring maximum flows are earlier than May 21, with an average about 17 days earlier. On the other hand, there are 11 historical traces where the dates of their spring maximum flows are earlier than May 21, with an average about 7 days earlier. The earlier shift of the climate spring maximum flow is consistent with the findings in the RMJOC report.[49]

Lastly, the monthly distributions of the daily TDA streamflows for the historical last 30 years, in the light blue boxplots, and the climate scenario A next 30 years, in the light red boxplots, are presented in

[49] *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

Figure D - 13. Since the boxplots are rather compact, the monthly distributions for the historical first 30 years are also included and plotted in the gray boxplots.

Figure D - 13: Comparison of Monthly Distributions of Historical and Climate Scenario A Daily Streamflows at TDA



In Figure D - 13 shows a consistent climate trend of increasing flows from October to April and decreasing flows from June to September (except for July between the two historical periods) among the three distriubtions. Also, it could be seen that the differences between the red boxplots and the blue boxplots are larger than the differences between the blue boxplots and the gray boxplots. Therefore, the climate trends, from the historical first 30 years to the historical last 30 years, and from the historical last 30 years to the next 30 years, became stronger over time.

Furthermore, the time-gap between the historical first 30 years (1929 to 1958) and last 30 years (1979 to 2008) is 51 years, and the time-gap beween the historical last 30 years to the next 30 years (2020 to 2049) is 42 years. Therefore, between the the historical last 30 years to the next 30 years, the climate trends not only became stronger, but they became stronger over a shorter amount of time (42 years). This suggests that the climate trends are accelerating (i.e., the rate of change of the climate trends are increasing).

It should be noted that there are a few days in May where all three distributions of streamflows have very high flows, at or greater than 1,000 KCFS. Before and during days with these very high flows, the hydro-system would require careful regulations to avoid flooding. This topic will be discussed in more details in a subsequent section.

For numerical comparisons, Table D - 4 below lists differences between the medians of the three distributions of streamflows. This table helps to illustrate the accelerated climate trends of streamflows from October to April, and from June to September (except for July between the two historical periods).

Table D - 4: Boxplot Statistics for Figure D - 13

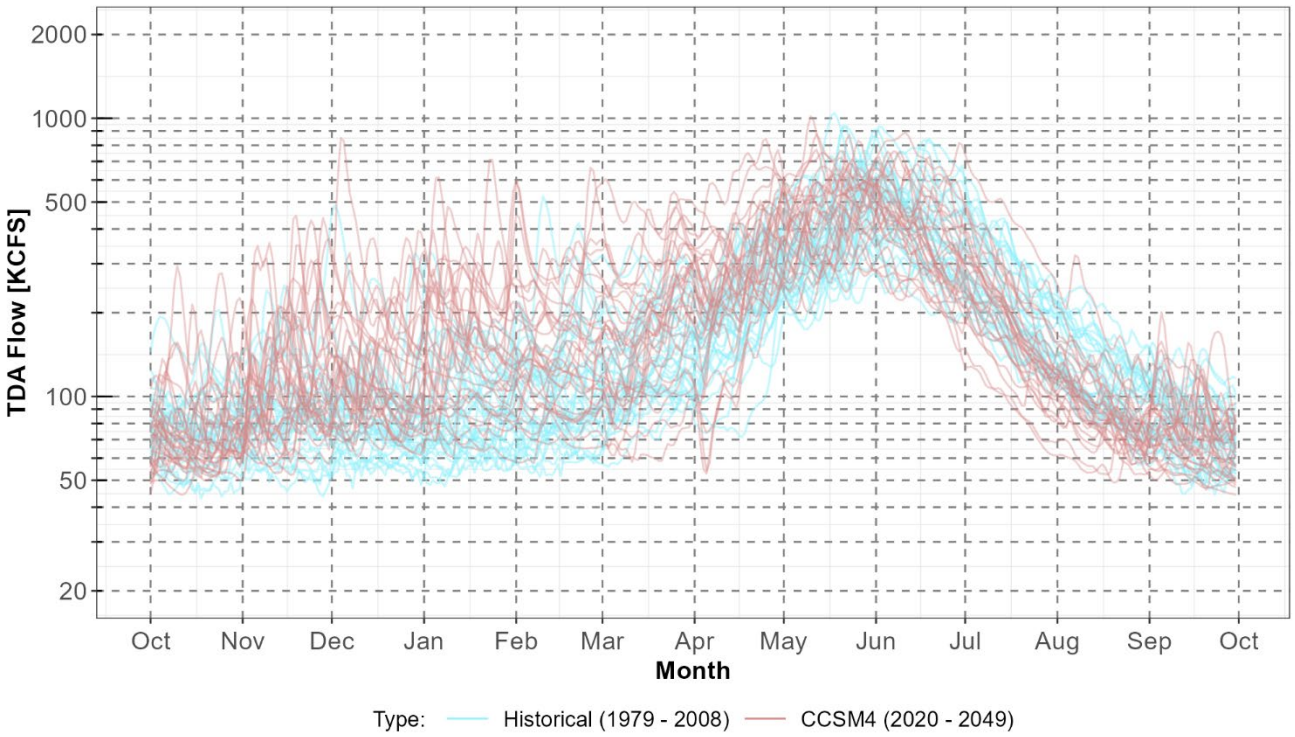
Month	$Median_{(last\ 30)} - Median_{(first\ 30)}$	$Median_{(Scen\ A)} - Median_{(last\ 30)}$
Oct	2.2	4.4
Nov	5.9	17.7
Dec	2.1	20.9
Jan	7.9	31.0
Feb	12.4	36.7
Mar	18.2	64.5
Apr	9.5	97.8
Jun	-10.9	-69.9
Jul	3.4	-56.4
Aug	-6.2	-24.0
Sep	-4.0	-5.2

Climate Scenario C

Next, Figure D - 14 to Figure D - 16 present the trace plots, envelope plots and boxplots, respectively, comparing TDA streamflows between the last 30 historical years and the scenario C (CCSM4 GCM) years from 2020 to 2049. Although the streamflow magnitudes, monthly shapes and monthly distributions are different between scenarios C and A, they both generally show the same climate trends relative to streamflows from the last 30 historical years, as discussed below.

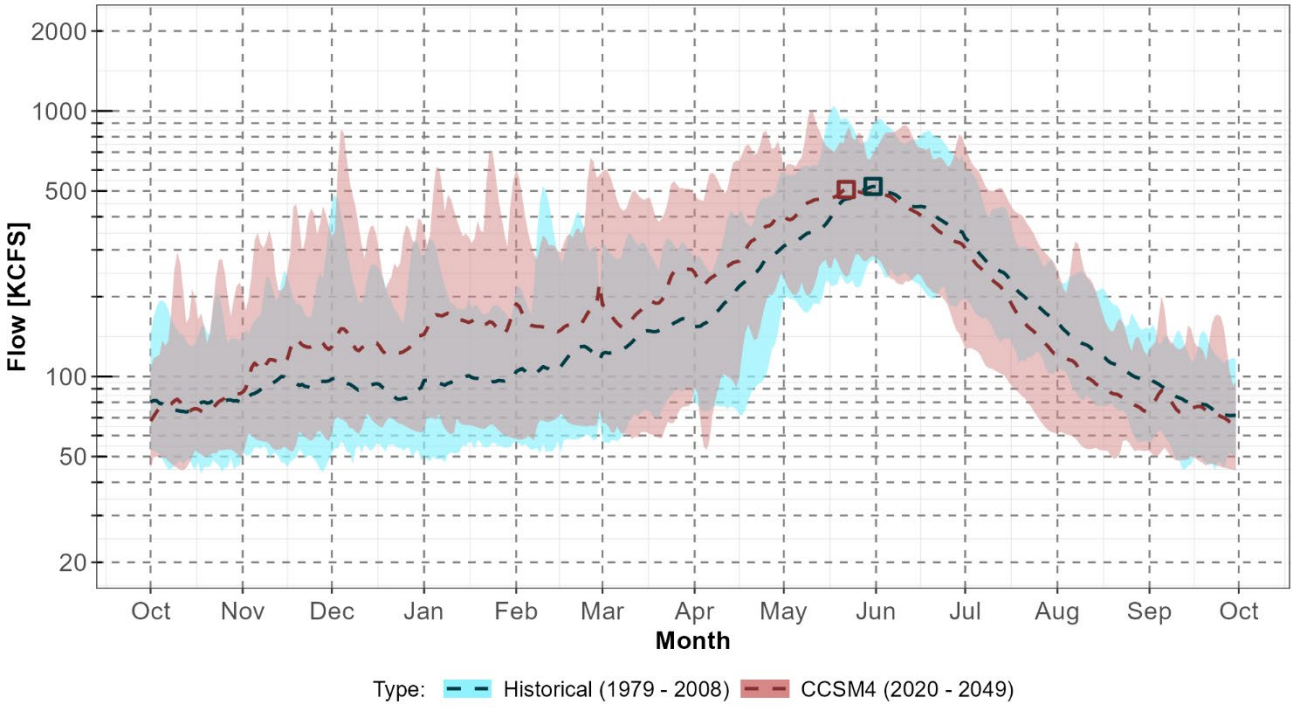
In Figure D - 14, it is evident that, for the 30 climate scenario C light red traces, its distribution from November to April is higher than that of the 30 light-blue historical traces. However, there are still one or two climate traces below the minimum historical traces for March and April. In contrast, for the three summer months from June to August, the distribution of climate traces is lower than that of the historical traces.

Figure D - 14: Comparison of Historical vs Climate Scenario C Daily Streamflows at TDA



Next, Figure D - 15 presents the envelope and average (in the dashed curves) plots. They show that, from November to May, the climate scenario C streamflows, represented by the light red area and dark red dashed curve, are generally higher than the historical flows represented by the light-blue area and dark blue dashed curve. The opposite is observed for June to August, where the envelope and dashed curves show that the climate scenario C streamflow is lower than the historical streamflow. In addition, the spring maximum of the climate average, in the red square, occurs 9 days earlier than the spring maximum of the historical average, in the blue square. These observations are nearly identical to those from Figure D - 12 which compares scenario A streamflows with historical streamflows.

Figure D - 15: Comparison of Historical and Climate Scenario C Streamflows



Finally, Figure D - 16 shows the monthly boxplot distributions of the daily TDA streamflows for the first 30 historical years, the last 30 historical years, and the climate scenario C years from 2020 to 2049, plotted in the gray, light blue, and light red boxplots, respectively.

Figure D - 16: Comparison of Monthly Distributions of Historical and Climate Scenario C Daily Streamflows at TDA

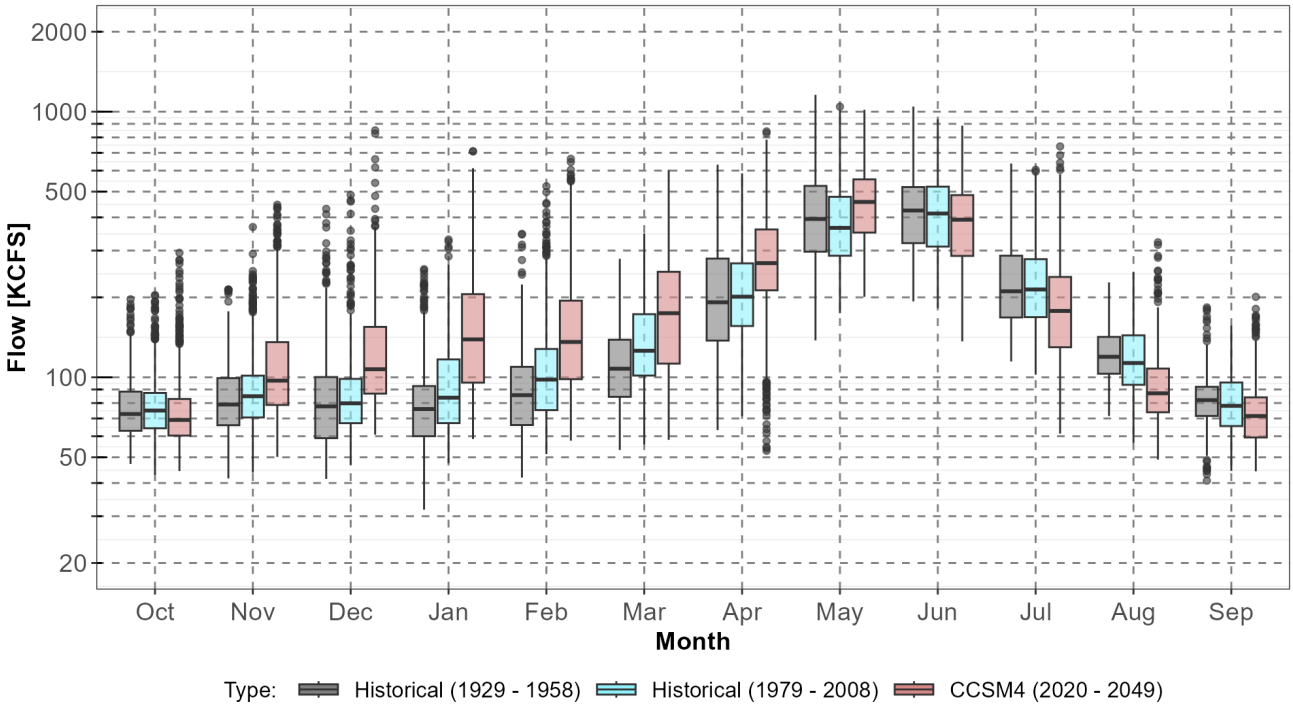


Figure D - 16 also shows the climate trends of increasing flows from November to April and decreasing flows from June to September (except for July) have accelerated between between the two historical periods and the scenario C period.

Differences of the medians among the three distributions of streamflows in Figure D - 16 are listed In Table D - 5, which support the climate trends are accelerating.

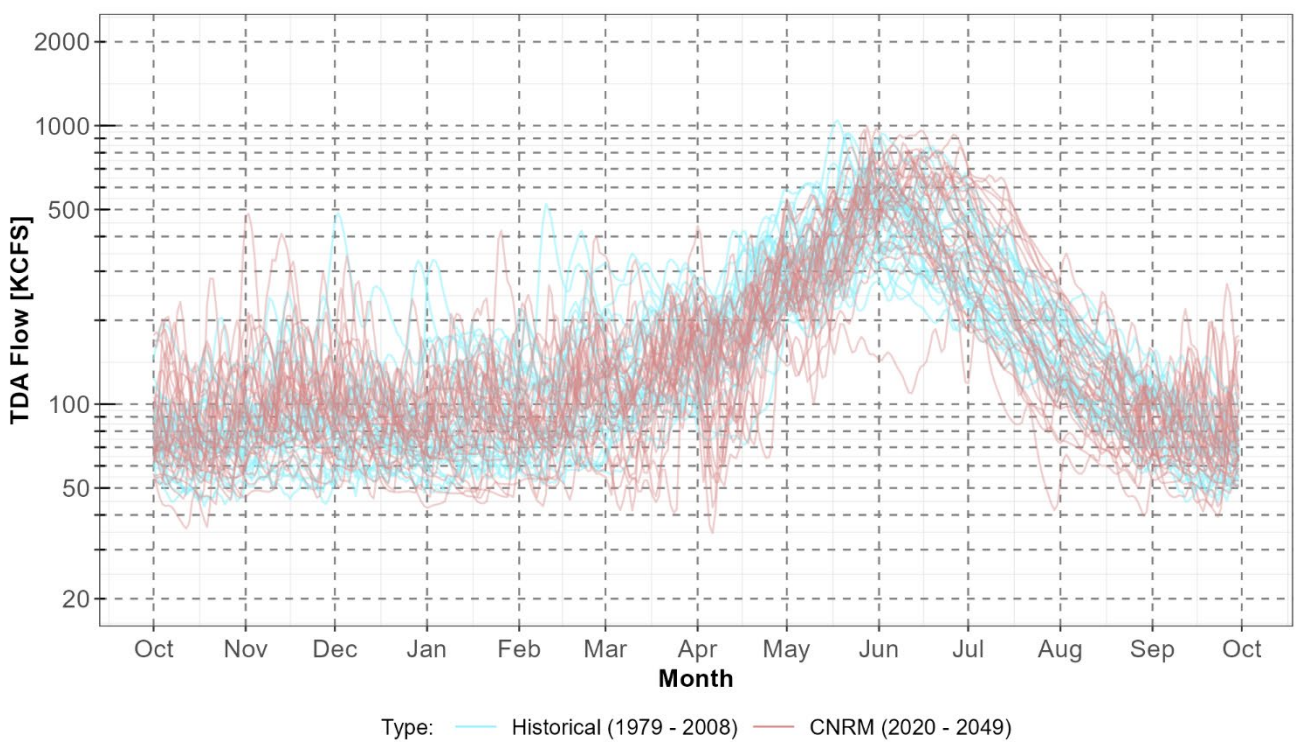
Table D - 5: Boxplot Statistics for Figure D - 16

Month	$Median_{(last\ 30)} - Median_{(first\ 30)}$	$Median_{(Scen\ C)} - Median_{(last\ 30)}$
Nov	5.9	12.3
Dec	2.1	27.4
Jan	7.9	55.0
Feb	12.4	37.8
Mar	18.2	48.4
Apr	9.5	67.9
Jun	-10.9	-21.6
Jul	3.4	-36.4
Aug	-6.3	-26.1
Sep	-4.0	-6.6

Climate Scenario G

Lastly, Figure D - 17 to Figure D - 19 present the trace plots, envelope plots and boxplots comparing TDA streamflows between the last 30 years of the historical data and the 2020 to 2049 period for scenario G (CNRM GCM).

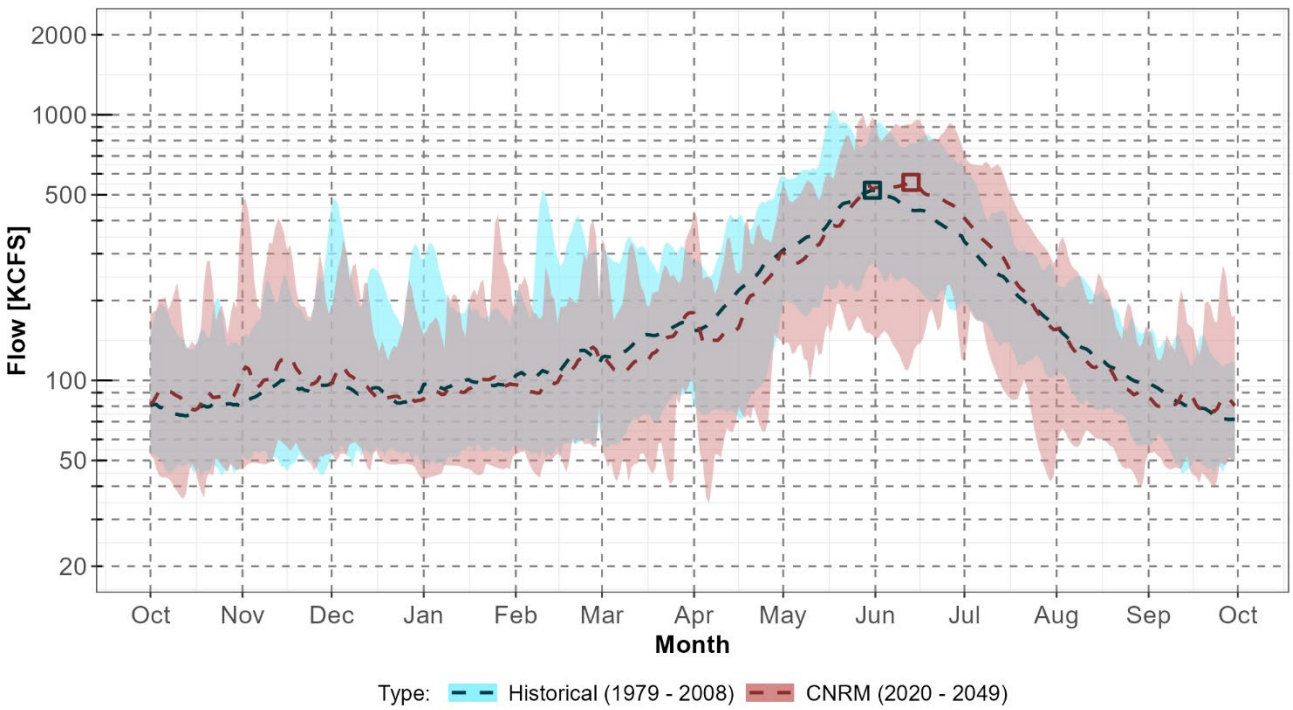
Figure D - 17: Comparison of Historical vs Climate Scenario G Daily Streamflows at TDA



Unlike the clear trends for scenarios A and C presented in Figure D - 11 and Figure D - 14 respectively, in Figure D - 17, the 30 climate scenario G light red traces do not suggest an obvious increase in streamflow for November to April, nor any decrease for June to August. There are however a few climate scenario G traces with low flows for March and April.

Next, the envelopes and averages for the climate scenario G and historical traces are plotted in Figure D - 18, along with the squares indicating the maximum spring average flows. The historical envelope and average are in the light-blue area and dark blue dashed curve while the climate envelope and average are in the light red area and dark red dashed curve.

Figure D - 18: Comparison of Historical and Climate Scenario G Streamflows

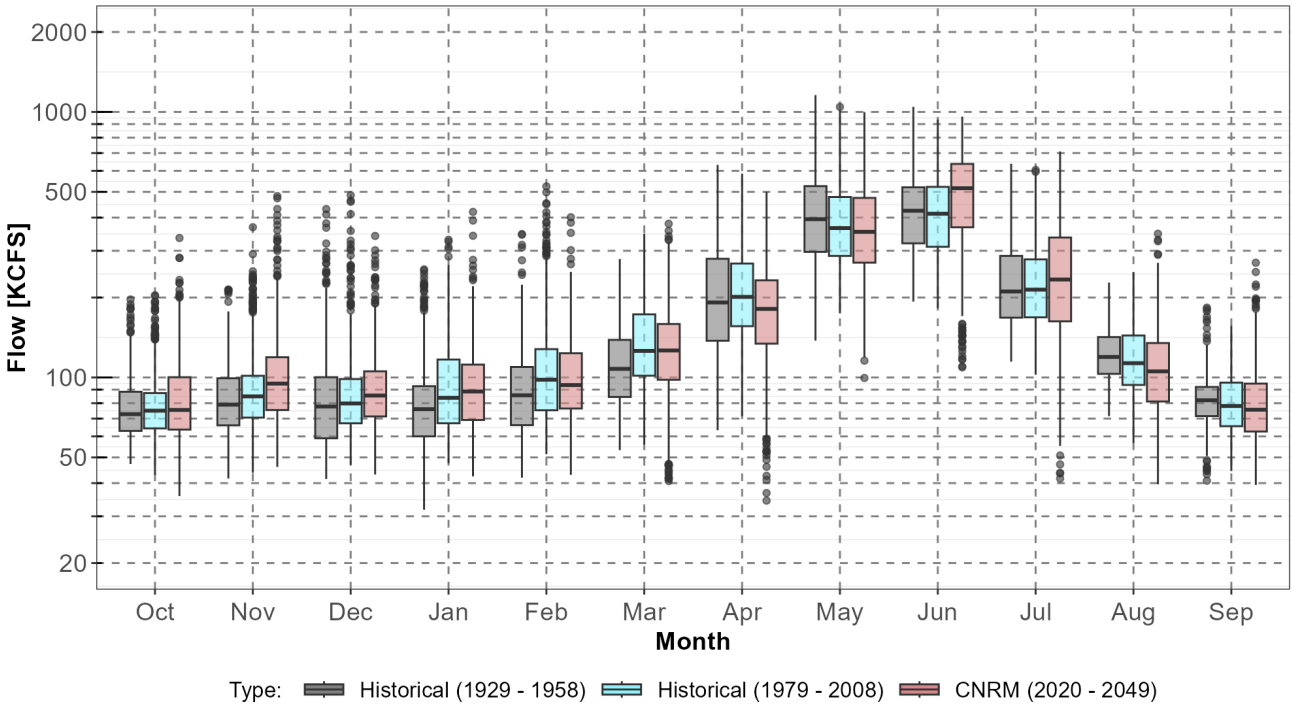


Comparisons of the envelopes and averages in Figure D - 18 show that flows are comparable between the climate scenario and the last 30 historical years for many months. The average flow for scenario G is generally slightly higher from October to December, slightly lower from January to May, but higher for June and July. Furthermore, the climate scenario maximum spring average flow occurs later (than the historical maximum spring average flow in the dark blue square) by 13 days. This is in contrast to those for scenarios A and C which occur earlier.

Thus, climate trends for scenario G are significantly different than those for scenarios A and C. The increase in average streamflow, observed from October to mid-May for climate scenario A and from November to May for climate scenario C, is not apparent in Figure D - 18 where the average streamflow for climate scenario G (in the dark red dashed curve) oscillates about the historical average (in the dark blue dashed curve). Conversely, the decrease in summer flows for June to August observed for climate scenarios A and C is actually reversed where the average for climate scenario G is higher than the historical average (for June and July).

Finally, in Figure D - 19, monthly distributions of the daily TDA streamflows for the first 30 historical years, the last 30 historical years, and the climate scenario G years are plotted in the gray, light blue, and light red boxplots, respectively.

Figure D - 19: Comparison of Monthly Distributions of Historical and Climate Scenario G Daily Streamflows at TDA



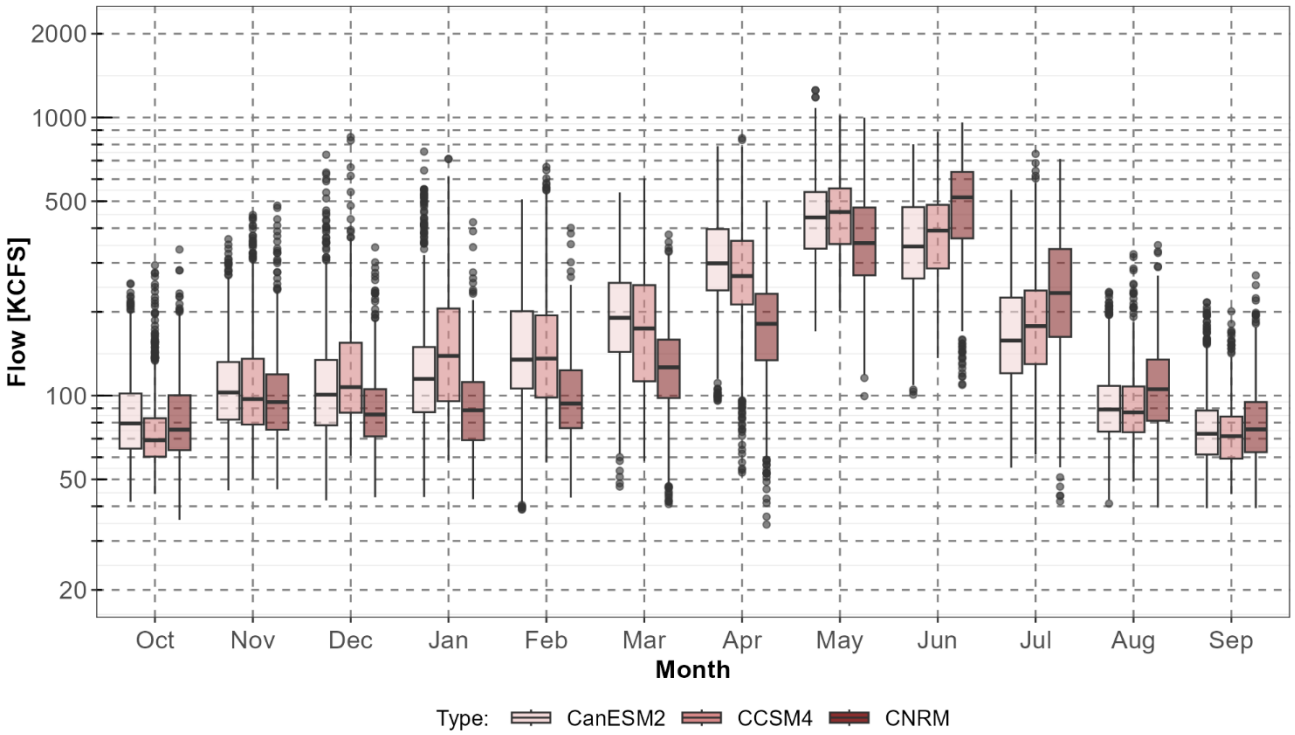
Boxplot comparisons of the monthly distributions show that streamflows for scenario G (light red boxplots) are slightly higher than the historical flows (last 30 years, in light blue) for November to January, where the median climate scenario streamflows are higher by less than 10 KCFS. However, climate scenario G streamflows are generally slightly lower than historical flows for February to May. In contrast, flows for scenarios A and C are significantly higher than historical flows over the same months. In addition, for the summer months the climate median flow is 102 KCFS (or 24.8%) higher for June, and 19.6 KCFS (or 9%) higher for July. The increasing flows in the two summer months for scenario G is opposite to the decreasing flows for scenarios A and C.

A Summary of the Three Climate Scenarios

In summary, all three climate scenarios show increasing TDA streamflows in mid-winter, from November to January, and decreasing streamflows in late summer and early fall, from August to September. In particular, climate scenarios A and C show increasing streamflows in spring, from March to May, and decreasing flows in early summer, from June to July. In contrast, for climate scenario G, streamflows decrease in spring, from March to May, and increase in early summer, from

June to July. These climate trends are consistent with findings in RMJOC report I.[50] Figure D - 20 presents boxplot comparisons of the monthly flows among the three scenarios.

Figure D - 20: Comparison of Monthly Distribution of Daily TDA Streamflows Across Climate Scenarios



In Figure D - 20, boxplots for scenario A (CanESM2), C (CCSM4), and G (CNRM), are plotted in light pale red, light red, and dark red, respectively. Compared to the flows for scenarios A and C, the flows for scenario G are lower for December to May, and higher for June to August. Flow comparisons between scenarios A and C show scenario A having higher flows in October, March and April, and scenario C having higher flows in December and January, and May to July. For the remaining four months, scenarios A and C have comparable flows where the differences between their median flows are less than 6 KCFS.

A possible explanation for scenario G having opposite climate-driven trends in streamflows than those for scenarios A and C is as follows. The RMJOC report I[51] shows that nearly all outputs from hydrological model VIC-P3, which was used in climate scenario G, show decreasing streamflows in

[50] *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

[51] See Figures 54 to 57 in *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

spring, from March to May, and increasing streamflows in early summer, from June to July. In contrast, all scenarios that were derived using hydrological model VIC-P1, which include both scenarios A and C, have the opposite seasonal trends of increasing streamflows in spring and decreasing streamflows in early summer. This observation suggests that the opposite climate-driven trends between scenarios G and A or C are primarily due to differences in the hydrological models and not primarily due to the GCMs themselves.

Very High and Very Low Streamflows

In addition to understanding power production from hydro generation, the Council's models also seek to ensure that other requirements for the hydro system are met. This includes fish and wildlife protection, flood control, river navigation, irrigation, and recreation. Regulating the hydro system to meet its many objectives becomes very challenging during time periods with very high or very low streamflows. Therefore, it is of interest to analyze and compare the frequencies of very high and very low streamflows in the historical period and future period as forecasted in the three selected climate scenarios.

Very High Streamflows

In general, high streamflows tend to enhance the hydro-system's ability to achieve its many objectives, among them are power generation, fish and wildlife protection, river navigation, and irrigation.

However, consecutive days of very high modified streamflows over one to two weeks could lead to flooding. For example, in Figure D - 8, the gray trace with very high streamflows from late May to early June, at or greater than 1,000 KCFS, represents the 1948 modified streamflows[52] at the Dalles. These very high flows led to catastrophic flooding at Vanport, Oregon, before some big storage hydro-projects were constructed. Besides 1948, there are three more water-years, 1972, 1974, and 1997, where modified streamflows in May or June also met or exceeded 1,000 KCFS.

With all the storage projects currently available, some hydro-regulation planning studies for these four water-years show that monthly averaged regulated[53] outflows at the Dalles in May or June are between 460 KCFS and 590 KCFS. Even with these lower outflows at the Dalles, the US Army Corps

[52] Since the Council's models use modified streamflows as inputs, therefore, all the TDA streamflows analyzed in this appendix have been modified streamflows. For consistency, analyses of very high and very low TDA streamflows will also be in terms of the modified streamflows. Other organizations also analyze a different type of streamflow, the No-Regulation-No-Irrigation (NRNI) flow.

[53] For example, at BPA, the model used for some long-term hydro-regulation studies uses monthly average modified streamflows as inputs, and the model outputs monthly averaged regulated outflows. Regulated outflow at a reservoir results from the modified flow (which is an inflow into the reservoir) under the influence of operations of the reservoir (i.e., the reservoir storing or discharging various volumes of water) and all upstream reservoirs.

of Engineers nevertheless determined that flooding begins when outflows reach 450 KCFS and flooding becomes significant for outflows reaching 600 KCFS.[54]

In comparison, among the 90 climate water-years from the three climate scenarios, there are just two water-years, 2047 of climate scenarion A (for seven consecutive days) and 2048 of climate scenario C (for one day), where the TDA modified streamflows exceed 1,000 KCFS in mid-May.

Figure D - 21 presents a jitter plot comparing historical and climate scenarios where TDA streamflows have consecutive days with magnitude greater than 1,000 KCFS. The x-axis are the water years, and on the y-axis are the consecutive daily TDA modified flows in KCFS. Historical water years are in green and water years from the climate scenarios are in light red.

Figure D - 21: Comparison of Historical and Climate Scenarios with Very High Streamflows at TDA

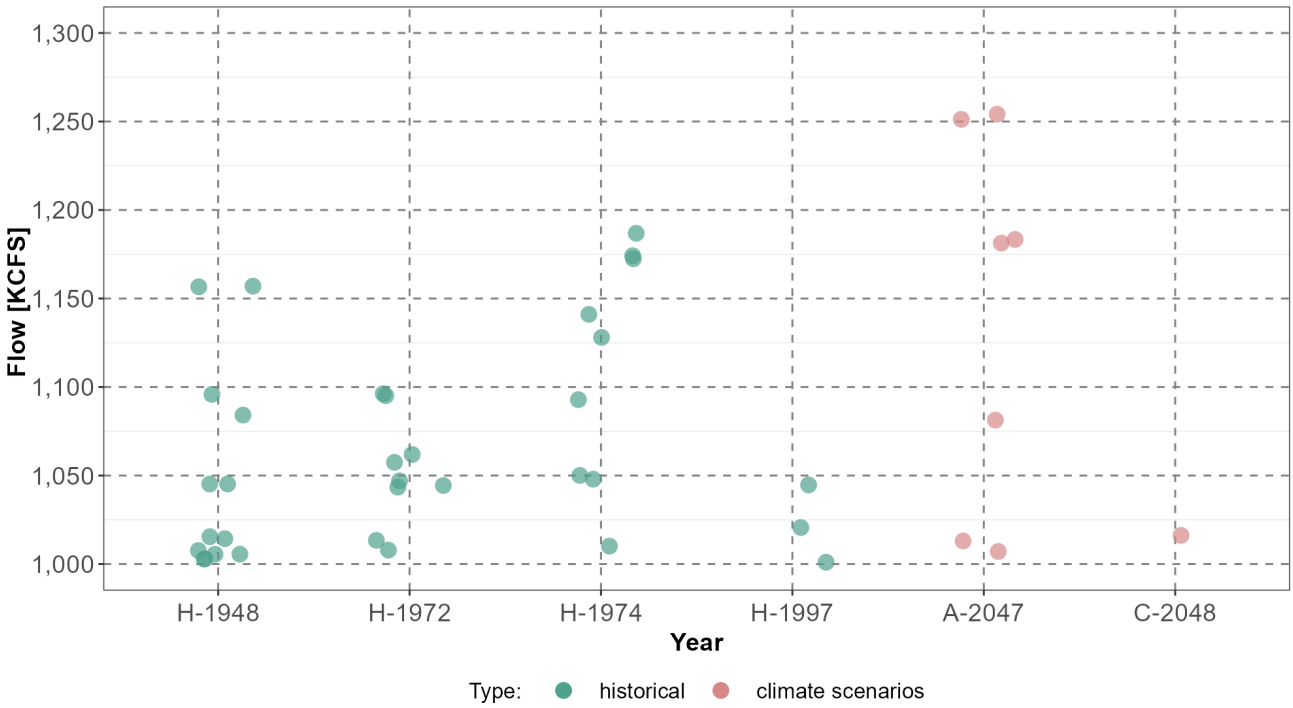


Figure D - 21 shows that for very high TDA daily modified flows, there were three historical water-years, 1948, 1972, and 1974, (ignoring the short three days in 1997). For those three years, there were between 9 to 13 consecutive days with flows greater than 1,000 KCFS. On the other hand, there is just one forecasted climate scenario water-year, 2047 in scenario A (ignoring the one day in climate

[54] *White Paper on COLUMBIA RIVER POST-2024, FLOOD RISK MANAGEMENT PROCEDURE*, U.S. Army Corps of Engineers, Northwestern Division, September 2011.

scenario year 2048 in scenario C). For year 2047 in scenario A, there are seven consecutive days with very high flows, and two of them have even higher flows than the highest historical flow.

Since the number of historical water-years, 80 (from the 2010 Level Modified Flow data set), is slightly smaller than 90, which is the number of climate scenario water-years, it could be concluded that there are fewer climate scenario water-years with many consecutive days of very high flows. This is likely due to smaller snowpacks whose runoffs contriubte significantly to streamflows in May in most climate scenario years.

Very Low Streamflows

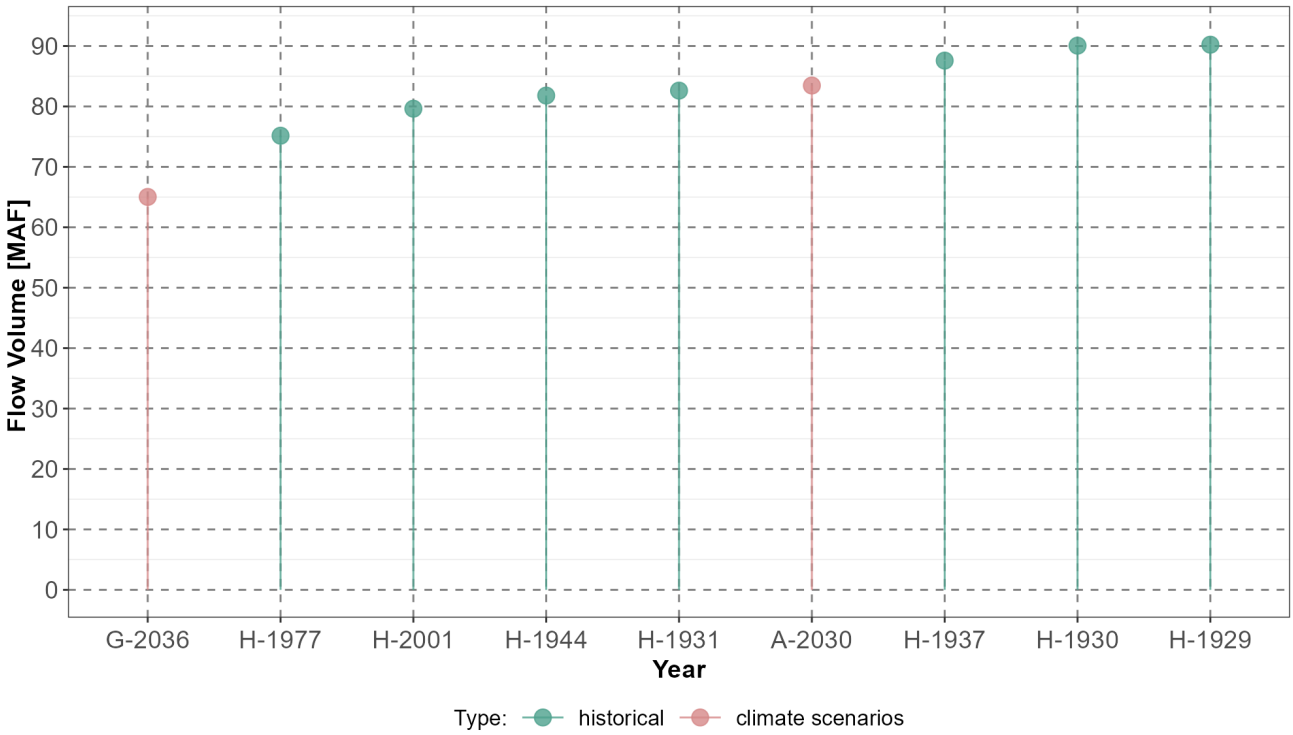
On the other hand, very low modified streamflows for couple of weeks in a month might still allow planners to operate the hydro-system to meet its objectives if there is enough streamflow volume in the previous month or the subsequent month. However, very low streamflows over a few months or longer would degrade the hydro-system's ability to meet many of its objectives.

Although there is no standard definition of very low streamflows, several historical water-years with very low annual or seasonal streamflow volumes had been used in various planning studies. For example, in the Columbia River Treaty,[55] the four consecutive critical water-years from 1929 to 1932 were used for planning treaty hydro-project operations for water years with very low streamflow volumes. In addition, in previous Bonneville Power Administration's Rate Case studies,[56] the critical water-year 1937 had been used to calculate the Firm Energy Load Carrying Capability (FELCC) of the (mainly hydro) power system. Aside from the planning studies, the historical 2001 water-year had very low annual and seasonal streamflow volumes that along with other factors contributed to the 2001 West Coast Energy Crisis.[57] Thus, the lowest annual and seasonal modified streamflow volumes at TDA for many of these historical water-years and other relevant water-years are presented in the following figures.

First, in Figure D - 22, the lowest TDA annual streamflow volumes are plotted for historical (in green) and climate scenario (in light red) water-years. For example, the historical water-year 1944 is designated as H-1944 on the x-axis, and water-year 2030 for climate scenario A is designated as A-2030 on the x-axis. The y-axis in this figure is the annual streamflow volume in million acre-feet (MAF).

[55] See https://share.google/SyoNsNh0gxCBwFf2J.
[56] See https://www.bpa.gov/-/media/Aep/rates-tariff/historic-rate-cases/bp-14/final-proposal/FINAL-BP-14-FS-BPA-03A-Power-Loads-and-Resources-Study-Documentation.pdf.
[57] See https://www.nwcouncil.org/reports/columbia-river-history/energycrisis.

Figure D - 22: Comparison of the Lowest Annual Streamflow Volumes at TDA



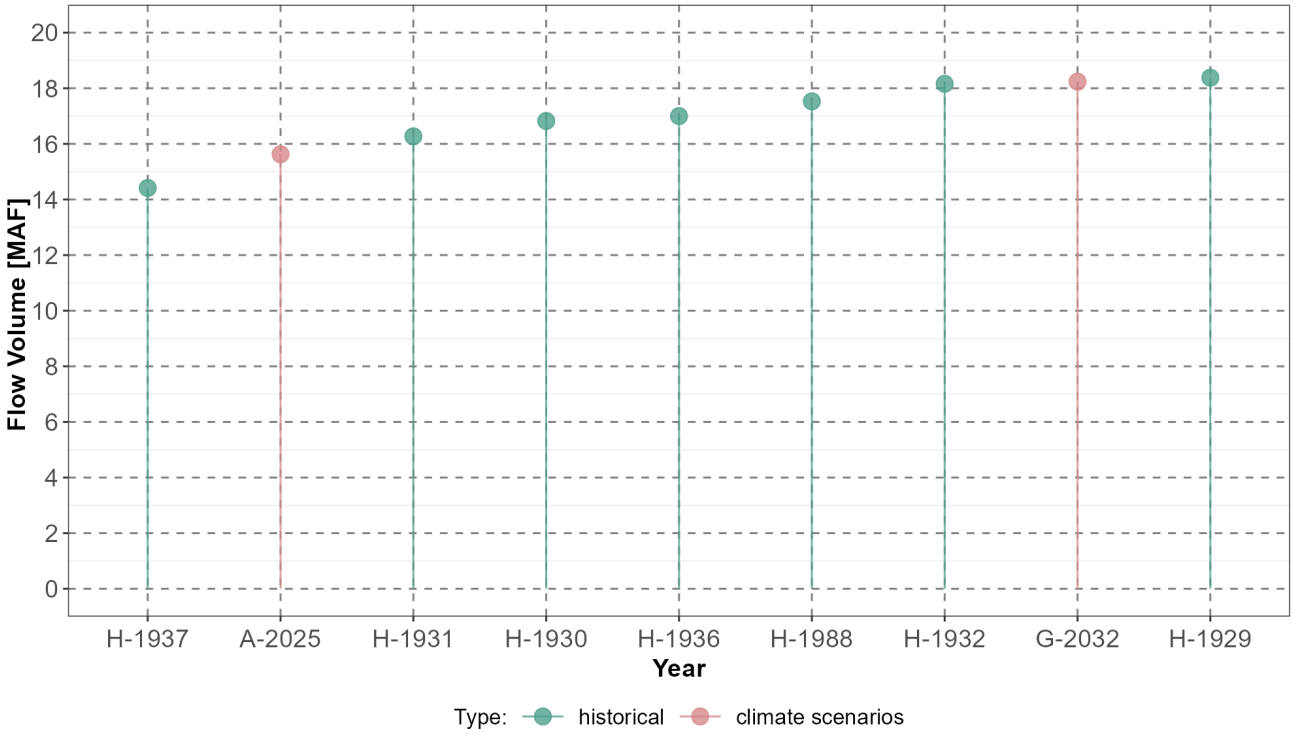
The lowest annual streamflow volumes are plotted in ascending order, where the lowest is the 65.0 MAF for climate water-year 2036 of scenario G. The next lowest volume is 75.2 MAF for the 1977 historical water-year. For convenience, only water-years with volume less than 91 MAF are plotted which include historical critical water-years from 1929 to 1931 and 2001.

Among these lowest annual volumes, there are seven historical water-years and only two climate water years, 2036 of scenario G and 2030 for scenario A. As presented previously, there are slightly fewer historical years (80) than climate scenario years (90), and thus it could be concluded that there are fewer climate water-years with very low annual volumes.

Operating the hydro-system to meet its many objectives is very challenging for these water-years with very low annual volumes. It is also useful to analyze streamflow volumes of seasonal subsets (of a water-year) that are likely to have high loads to further narrow the months during which the hydro-system is under stress to generate power and still meet its other objectives.

The October to February time period covers the beginning of a water-year through the winter months, and its streamflow volume is a significant portion of water available to plan operations of the hydro-system to meet high winter loads and other objectives. Therefore, in Figure D - 23, the lowest TDA October to February seasonal volumes are plotted for historical and climate water-years in ascending order, where the lowest is the 14.4 MAF for the historical year 1937. The next lowest volume is 15.6 MAF for climate water-year 2025 of scenario A. For convenience, only years with volumes less than 18.5 MAF are plotted, which include historical critical water-years from 1929 to 1932.

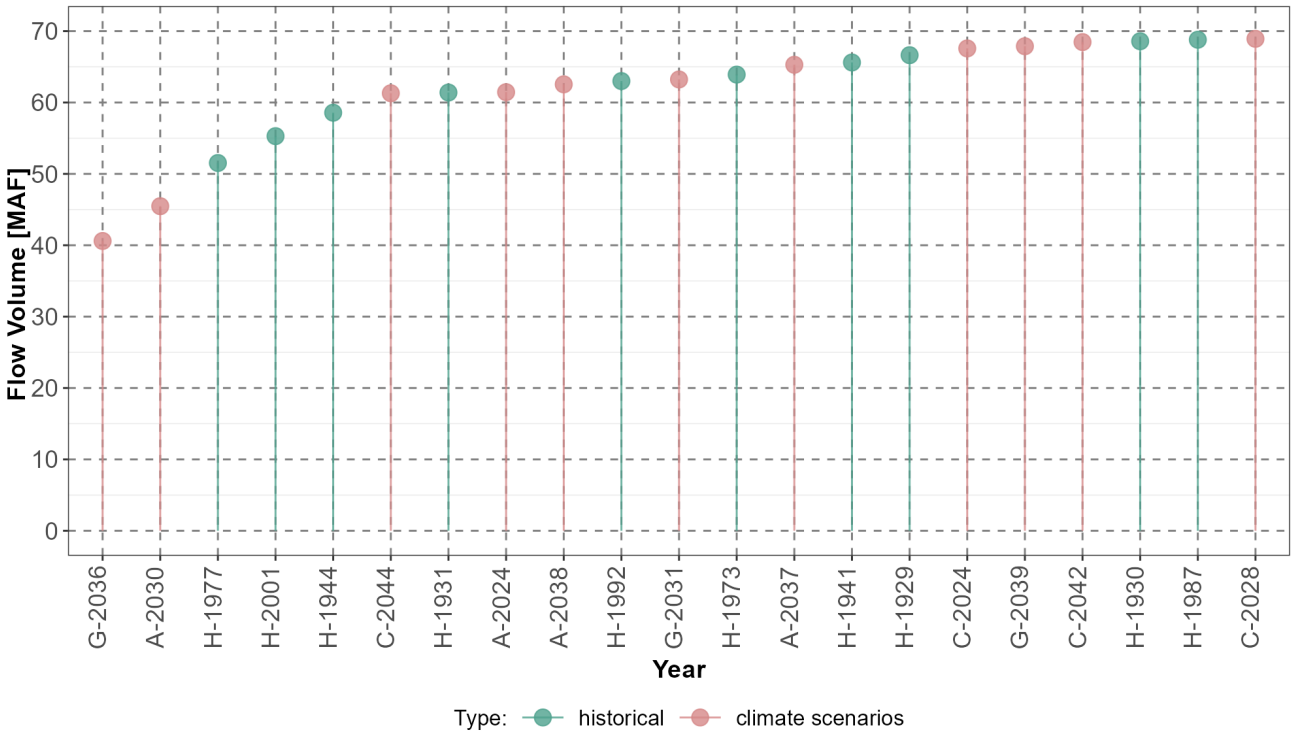
Figure D - 23: Comparison of Lowest October to February Streamflow Volumes at TDA



Among these lowest October to February volumes, there are seven historical water-years (in green) and only two climate scenario water years (in light red): 2025 of scenario A and 2032 of scenario G. The lowest volume is 14.4 MAF for historical year 1937 and the next lowest is 15.6 MAF for climate water-year 2025 of scenario A. Since there are slightly fewer historical years (80) than climate scenario years (90), it could be concluded that there are fewer climate water-years with very low October to February volumes.

Finally, the April to September time period covers the usual beginning of snowpack runoff through the summer months, and its streamflow volume is a major portion of water available to plan operations of the hydro-system to meet high summer loads and other objectives. Therefore, in Figure D - 24, the lowest TDA April to September seasonal volumes are plotted for historical (in green) and climate water-years (in light red) in ascending order, where the two lowest are 40.6 MAF and 45.5 MAF for climate water-years 2036 of scenario G and 2030 of scenario A, respectively. The next two lowest are 51.5 MAF and 55.3 MAF for historical years 1977 and 2001, respectively. Only years with volumes less than 69 MAF are plotted, which include historical critical water-years from 1929 to 1931 and 2001.

Figure D - 24: Comparison of Lowest April to September Streamflow Volumes at TDA



Among these lowest April to September volumes, there are 10 historical water-years and 11 climate water years. Since there are slightly fewer historical years (80) than climate scenario years (90), it could be concluded that there are about the same number of historical and climate water-years with very low April to September volumes.

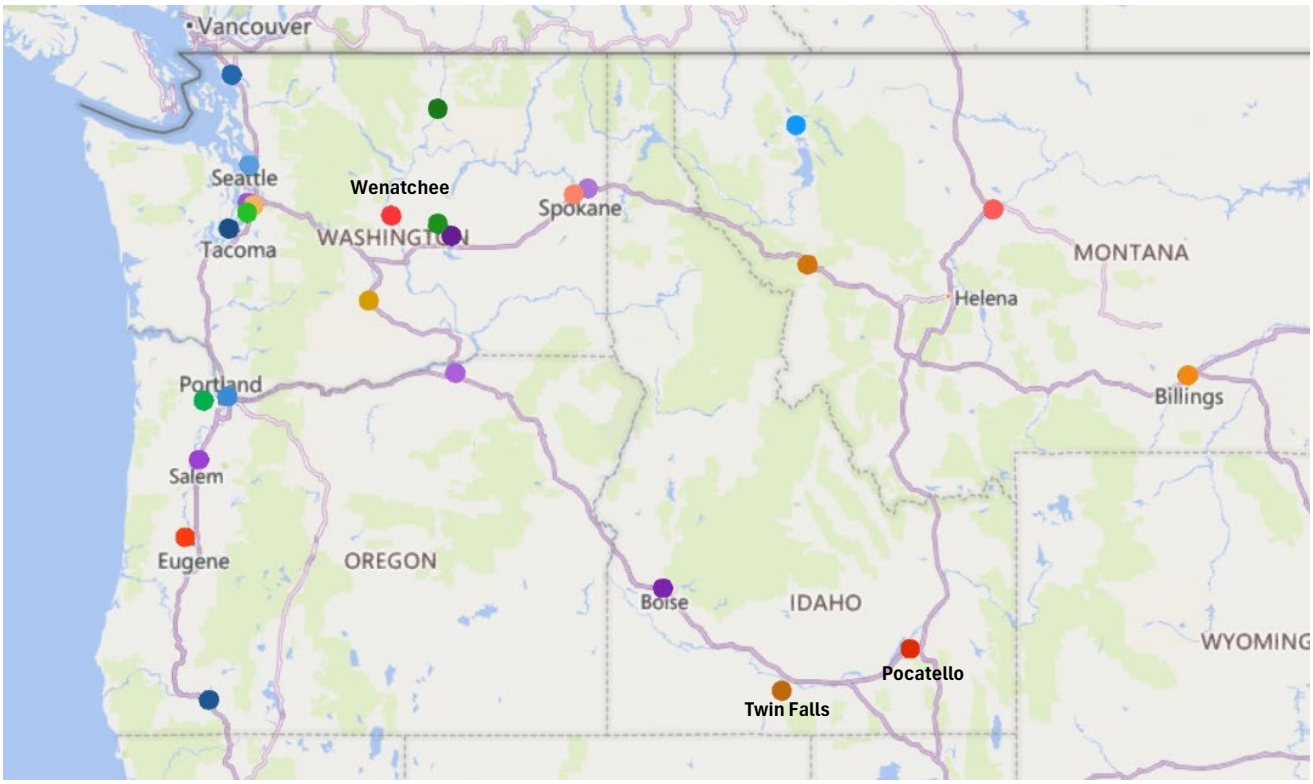
Trends in Historical and Climate Scenario Temperatures

For the Ninth Plan, the Council has decided to also use temperature data, along with streamflow data, from three of the 19 climate scenarios developed by the RMJOC. The RMJOC temperature data are inputs in the Council's simulation models to forecast loads. They are also used to develop climate scenario wind and solar generations, the details of which are presented in subsequent sections.

For forecasting loads, the Council's simulation model, developed by Itron, produces load forecasts for the 13 regional balancing authorities (BAs).[58] Various combinations of temperatures at 26 locations in the region are used as inputs for the 13 BAs, and plotted in Figure D - 25 below.

[58] See Technical Appendix F - Electricity Demand Forecast in the Ninth Power Plan for more details.

Figure D - 25: RMJOC Temperature Locations



For example, the temperatures of three cities in Idaho are used as inputs for the Idaho Power BA: Pocatello, Twin Falls, and Boise. On the other hand, only one temperature in central Washington is used for the Chelan Public Utility District BA: Wenatchee.

Climate Trends

Since it is not practical to analyze trends in historical or climate temperatures for all 26 locations, only those at the four largest metropolitan areas, in terms of population, are selected for analysis: Boise, Portland, Seattle, and Spokane. Furthermore, the four cities are spread sufficiently far enough from each other that they capture some of the different climate characteristics of the region.

The warming trend of historical temperatures is well known[59] and the forecast of higher warming in the future is also well documented.[60] In this section, warming trends of historical and climate scenario temperatures at the four metropolitan areas are analyzed in detail.

Since the RMJOC climate scenario temperature data are daily minimum and daily maximum temperatures at the airports of the four cities, then historical temperatures at the four airports are

[59] See https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature
[60] See https://cig.uw.edu/learn/climate-change.

downloaded from the NOAA website[61] for analysis. For simplicity, the airports are abbreviated as follows: BOI for Boise, GEG for Spokane, PDX for Portland, and SEA for Seattle. Although historical data at the four airports are available with different starting dates, nevertheless, they are all available starting on 1/1/1948. Thus, the historical data are 77 years of daily minimum and daily maximum temperatures from 1/1/1948 to 12/31/2024. In contrast, the daily climate scenario temperature data are the 30 years from 1/1/2020 to 12/31/2049 as used in the Power Plan

Before presenting the temperature analyses, it should be noted that the RMJOC climate scenario temperatures used in the Ninth Plan and in this section have been adjusted. The reason is that some climate scientists from the CWAC, based on their research, felt that some climate scenario temperatures at Seattle and Portland are unrealistically low. Specifically, the lowest daily minimum temperature around -4 F at SEA and -15 F at PDX from climate scenario G are too low. Some of the climate scientists believe that the original grid size of scenario G, about 1 to 2 degrees longitude and latitude, is too large to accurately model the Rocky Mountain range, and thus not able to prevent very cold temperatures from the interior east moving to the coastal west region.[62] As a solution, they suggested that these unrealistically low temperatures be substituted with the corresponding lowest historical observed temperatures, which are listed in Table D - 6.

Table D - 6: The Lowest Historical Temperatures in [F] at the Four Airports

BOI	GEG	PDX	SEA
-25	-25	-3	0

There are nine days out of the 90 climate scenario years where some of the climate temperatures at the four airports are below their corresponding historical lowest temperatures in Table D - 6 above: two days at BOI (-27, -29); three days at GEG (-27, -32, -34); one day at PDX (-15); and three days at SEA (-1, -1 and -4).

Even though climate scientists from the CWAC suggested changing only the two specific airports, at SEA and PDX, for consistency of analysis in this section, all climate scenario temperatures from those nine days at the four airports that are below their corresponding lowest historical temperatures listed in Table D - 6 are substituted with their corresponding historical temperatures.

Similarly, for consistency as inputs into the load forecast model, climate scenario temperatures at all 26 locations are also adjusted so that if their daily minimum temperatures are below their corresponding lowest historical temperatures, they are then substituted with the corresponding lowest historical temperatures.

[61] https://www.ncei.noaa.gov/cdo-web/search.

[62] Climate and Weather Advisory Meeting on 12/4/2024: https://www.nwcouncil.org/meeting/climate-and-weather-advisory-committee-2024-12-04.

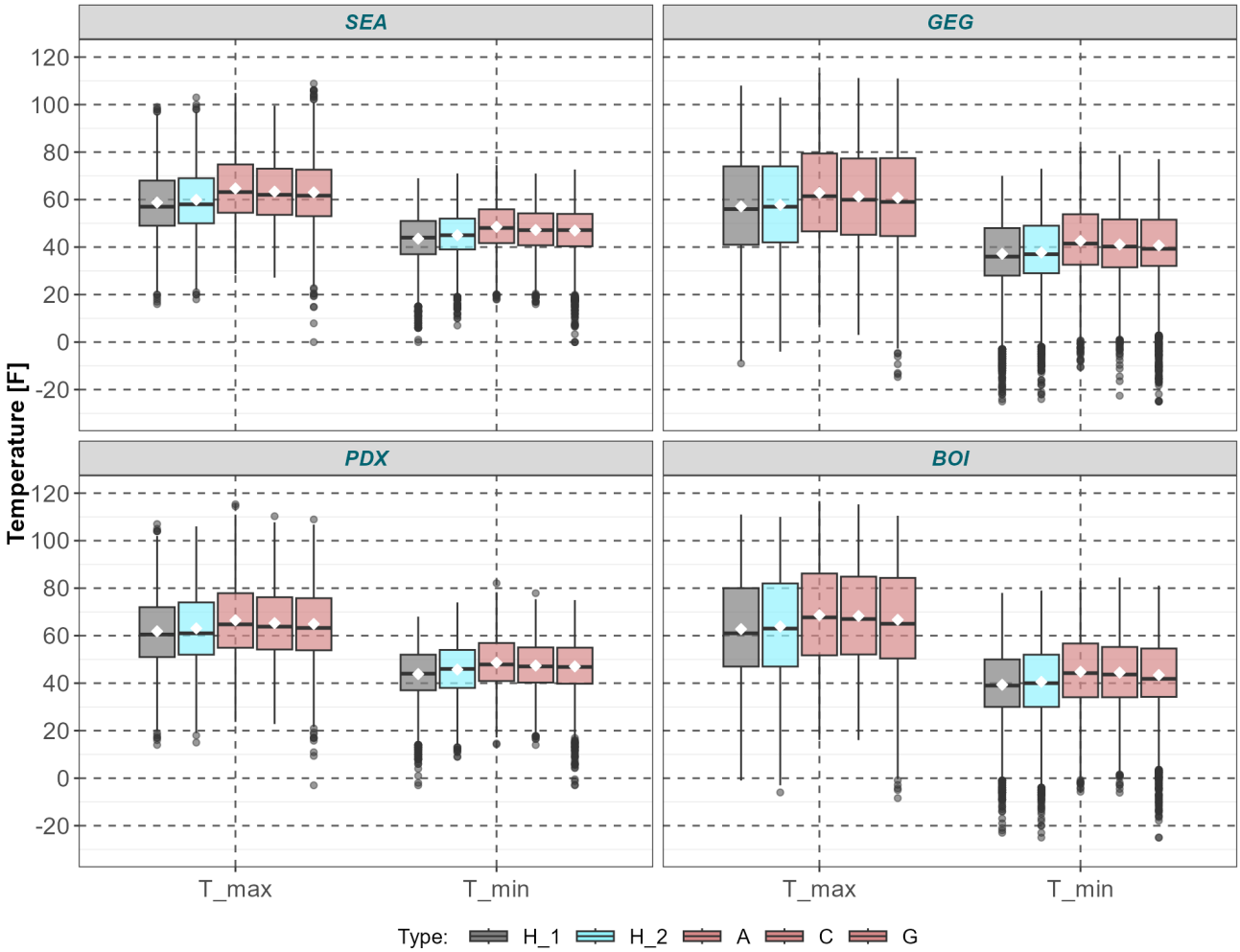
Overall Trends

There are 77 years of historical temperature data, from 1948 to 2024, and as used in the Power Plan, 30 years of forecasted temperature data, from 2020 to 2049, from each of the three climate scenarios. To analyze the warming trends in a systematic way, three sets of temperature data, each consisting of 30-years of temperatures, are used. The data sets are as follows: the *first historical 30-years*, designated as H_1 which begins in 1948 and ends in 1977; the *next historical 30-years*, designated as H_2, which begins in 1984 and ends in 2013; and finally, the *climate scenario 30-years* which begins in 2020 and ends in 2049, for each of the three climate scenarios. The years in H_1, H_2, and the climate scenario 30-years, are selected such that there is an equal gap of 37 years for warming trend to evolve between the sets. Specifically, there are 37 years between the first year of H_1 (1948) and the first year of H_2 (1984), and between the first year of H_2 (1984) and the first year of the climate scenario years (2020). Having an equal time gap between H_1 and H_2, and between H_2 and the climate scenario years, allows an equal amount of time for the warming temperatures to develop between between the three time periods, and comparison of changes in temperatures among the three time periods would be fair.

Therefore, if the increase in temperature between H_1 and H_2 is less than that between H_2 and the climate scenario 30-years, then it could be concluded that the warming trend has increased over time. On the other hand, if the increase in temperature between H_1 and H_2 is greater than that between H_2 and the climate scenario 30-years, then the warming trend has decreased over time. These conclusions are possible due to the equal time gap of 37 years among the three time periods.

Boxplots of the distributions of the daily maximum and daily minimum temperatures of the two historical sets H_1 and H_2, and climate scenarios A, C, and G, at the four cities are plotted in Figure D - 26.

Figure D - 26: Distributions of Daily Maximum and Minimum Temperature at the Four Cities



In Figure D - 26, the distributions of daily temperatures at the four cities are plotted in four separate panels arranged in their relative geographical locations: SEA at top left; GEG at the top right; PDX at the bottom left; and BOI at the bottom right. Furthermore, in each panel, the daily maximum temperatures are on the left while the daily minimum temperatures are on the right. In addition, the historical and climate temperatures are plotted in different color boxplots: gray for H_1, light blue for H_2, and light red for the three climate scenarios. Specifically, the left red boxplot represents A, the middle red boxplot represents represents C, and the right red boxplot represents G. Finally, the white diamond inside each boxplot represents the average of the distribution.

It could be seen that (except for the daily minimum temperatures at PDX) both the daily maximum and minimum temperature distributions for H_2 have *not increased significantly* from those for H_1. On the other hand, both the daily maximum and minimum temperature distributions of all three climate scenarios are *higher* than those for H_2. Since the gap between H_1 and H_2, and between H_2 and the climate scenario years are the same at 37 years, then the warming trends have increased over time (except for the daily minimum temperatures at PDX). Furthermore, among the three climate scenarios, A has the highest warming and G has the lowest warming. In addition, the variances of the

daily minimum temperatures are less than the corresponding variances of the daily maximum temperatures.

To quantify the warming trends of the daily maximum temperatures T_{max}, differences of the averages of the five distributions (the white diamonds inside the boxplots) are tabulated in Table D - 7 for the four cities.

Table D - 7: Differences of the Averages of the Daily Maximum Temperature Distributions in [F]

T_{max}	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
BOI	+ 1.1	+ 4.8	+ 4.4	+ 2.8
GEG	+ 0.6	+ 5.0	+ 3.5	+ 3.0
PDX	+ 1.2	+ 3.4	+ 2.2	+ 1.9
SEA	+ 1.2	+ 4.8	+ 3.4	+ 3.1

Similarly, for the daily minimum temperatures T_{min}, differences of the averages of the five distributions are tabulated in Table D - 8 for the four cities.

Table D - 8: Differences of the Averages of the Daily Minimum Temperature Distributions in [F]

T_{min}	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
BOI	+ 1.2	+ 4.2	+ 3.9	+ 2.9
GEG	+ 0.6	+ 4.9	+ 3.4	+ 3.0
PDX	+ 1.9	+ 2.9	+ 1.7	+ 1.3
SEA	+ 1.5	+ 3.5	+ 2.2	+ 1.9

Both Table D - 7 and Table D - 8 support the following qualitative climate trends in Figure D - 26:

- The distributions of both daily maximum and daily minimum temperatures for H_2 are only slightly higher that those for H_1 (except for the daily minimum temperatures at PDX).
- The distributions of daily maximum and daily minimum temperatures for the three climate scenarios are higher than those for H_2.
- The warmings of the three climate scenario temperatures relative to H_2 are higher than the corresponding warmings of H_2 of relative to H_1 (except for the daily minimum temperatures at PDX). Therefore, the warming trends have increased over time excluding the noted exception at PDX.

However the following trend holds for both types (daily maximum and daily minimum) of temperature distributions at all four cities:

- Among the three climate scenarios, A has the highest warming and G has the lowest warming.

Because very low temperatures in the winter months and very high temperatures in the summer months are likely to contribute to very high loads, then it is also useful to analyze climate trends for the winter, and summer subsets of the overall distributions already analyzed in this section. For completeness, climate trends for other seasonal subsets are also analyzed.

In addition, further analyses show that the daily maximum temperatures and daily minimum temperatures are highly correlated for the five data sets plotted in Figure D - 26 . Specifically, the correlation coefficients are, at BOI, at or greater than 0.92; at GEG, also at or greater than 0.92; at PDX, between 0.80 and 0.88; and at SEA, between 0.84 and 0.89. Because of the high correlation between the daily maximum and daily minimum temperatures, in the next four sections, for simplicity, climate trends for the seasons are analyzed using either the daily maximum or the daily minimum temperatures as appropriate. For example, for the winter months, the daily minimum temperatures are analyzed, while for the summer months, the daily maximum temperatures are analyzed.

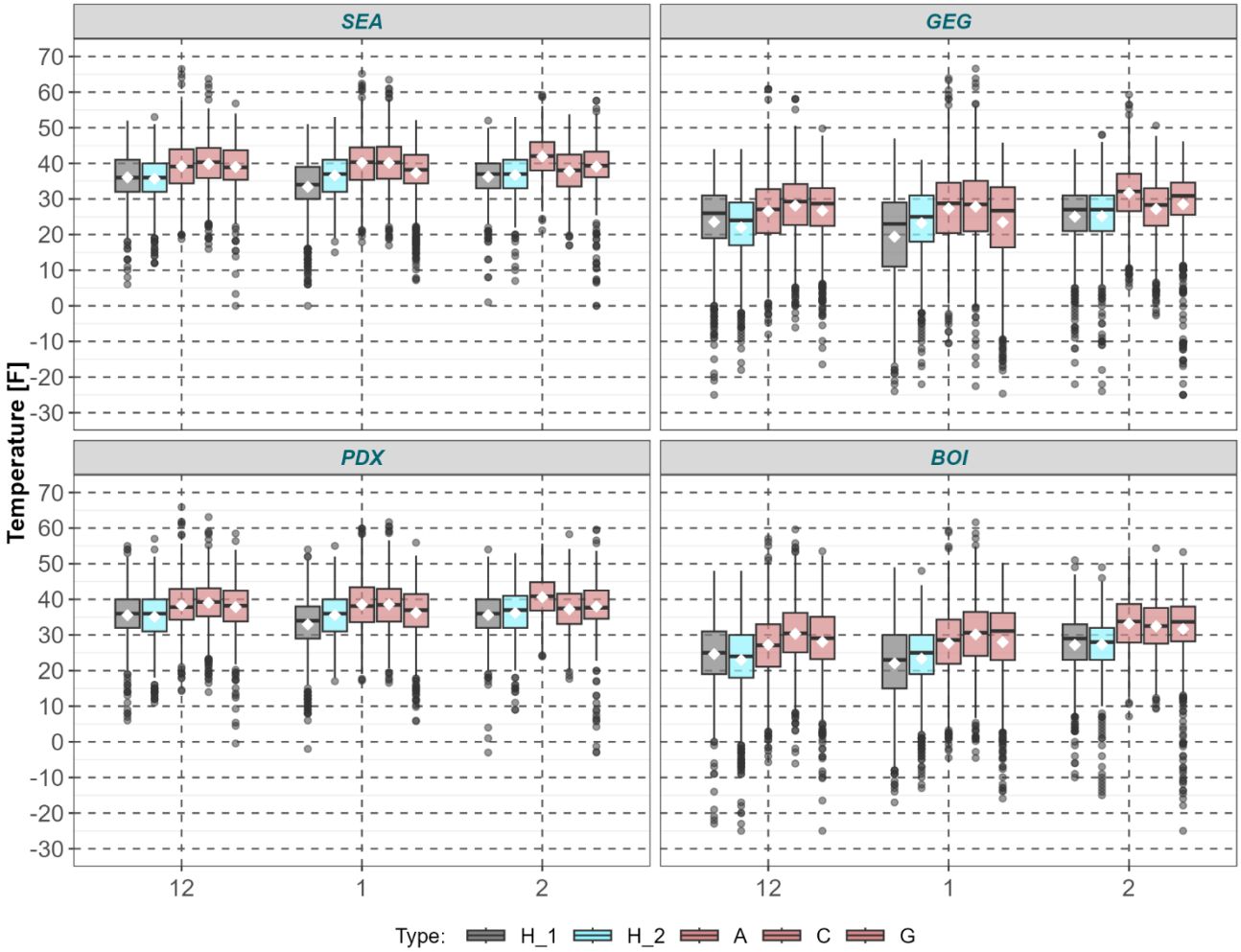
Analyses in subsequent sections also include discussions of heating degree-days (HDDs) and cooling degree-days (CDDs), and their calculations, by definition, involve both the daily maximum and daily minimum temperatures. However, because of the high correlation between the daily maximum and minimum temperatures, analyses of HDDs are simplified to involve only the daily maximum temperatures, and conversely, analyses of CDDs are simplified to involve only the daily minimum temperatures.

Trends in the Winter Months

For the Northwest region, the winter months are usually defined as December, January, and February, and loads during these months are generally the highest. In Figure D - 27 are the boxplots of the distributions of the daily minimum temperatures for the winter months of the two historical sets H_1 and H_2, and climate scenarios A, C, and G, for the four cities. This figure shows winter months showing the same climate trend as presented in the previous section: warming temperatures from H_1 to H_2 to the climate scenario years as presented in the previous section. Therefore, the distribution of HDDs of the climate scenario temperatures will be lower than the distribution of HDDs of the historical temperatures in H_2, which in turn will be lower than the distribution of HDDs of the historical temperatures in H_1.

The forecasted loads follow the trends in the HDDs and thus, the distribution of forecasted loads using the climate scenario temperatures is lower than using historical temperatures in H_2, which in turn is lower than using historical temperatures in H_1.

Figure D - 27: Distributions of Winter Daily Maximum and Minimum Temperature at the Four Cities



From Figure D - 27, the distributions of daily minimum temperatures at the near coastal cities, SEA and PDX, are higher than those at the inland cities, GEG and BOI. Furthermore, the aggregate warmings of the daily minimum temperatures for all 12 months in Figure D - 26 are not spread uniformly over the three months in Figure D - 27. The differences of the averages between the five distributions are tabulated in Table D - 9 to Table D - 12 for the four cities. In each of the four Tables, the the highest warmings by month are bolded.

It is interesting that in the historical data that December has cooled for H_2 compared to H_1. Otherwise, over all three months at all four cities, it is the expected climate trend of warming temperatures from H_1 to H_2 to the climate scenario years. Therefore, it could be deduced that the forecasted loads using climate scenario temperatures on average will be lower than those forecasted using historical temperatures in H_1 and H_2.

Table D - 9: Differences of the Averages of the Daily Minimum Temperature Distributions in [F] for BOI for Months 12, 1, 2

$BOI/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
12	- 1.7	+ 4.3	**+ 7.4**	**+ 5.1**
1	**+ 1.3**	+ 4.4	+ 6.8	+ 4.6
2	+ 0.1	**+ 5.9**	+ 5.1	+ 4.3

Table D - 10: Differences of the Averages of the Daily Minimum Temperature Distributions in [F] for GEG for Months 12, 1, 2

$GEG/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
12	- 1.5	+ 4.6	**+ 6.1**	**+ 4.7**
1	**+ 3.8**	+ 4.1	+ 4.6	+ 0.2
2	+ 0.1	**+ 6.6**	+ 2.0	+ 3.4

Table D - 11: Differences of the Averages of the Daily Minimum Temperature Distributions in [F] for PDX for Months 12, 1, 2

$PDX/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
12	- 0.5	+ 3.2	**+ 4.0**	**+ 2.7**
1	**+ 2.6**	+ 2.9	+ 3.0	+ 0.7
2	+ 0.6	**+ 4.4**	+ 1.0	+ 1.8

Table D - 12: Differences of the Averages of the Daily Minimum Temperature Distributions in [F] for SEA for Months 12, 1, 2

$SEA/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
12	- 0.4	+ 3.5	**+ 4.2**	**+ 3.3**
1	**+ 3.2**	+ 3.6	+ 3.5	+ 0.7
2	+ 0.5	**+ 5.2**	+ 1.1	+ 2.4

Moreover, from H_1 to H_2, the month with the highest warming is January. However, for climate scenario A, the month with the highest warming is February, while for scenarios C and G, the month with the highest warming is December. Overall, all three winter months and at all four cities, it is the usual climate trend that climate scenario A has the highest warming and scenario G has the lowest warming, with one exception: at BOI, climate scenario C that has the highest warming.

However, as plotted in Figure D - 27, climate scenario G, despite on average, having warmer (daily minimum) temperatures than both historical data sets, still on occasions has comparatively very low temperatures as compared to the historical sets at all four cities. It should be reminded that some of the lowest temperatures in G that are below the lowest historical temperatures have been adjusted to be equal to those lowest historical temperatures. A more detailed analysis of these very cold temperatures of the four cities are presented in a subsequent section.

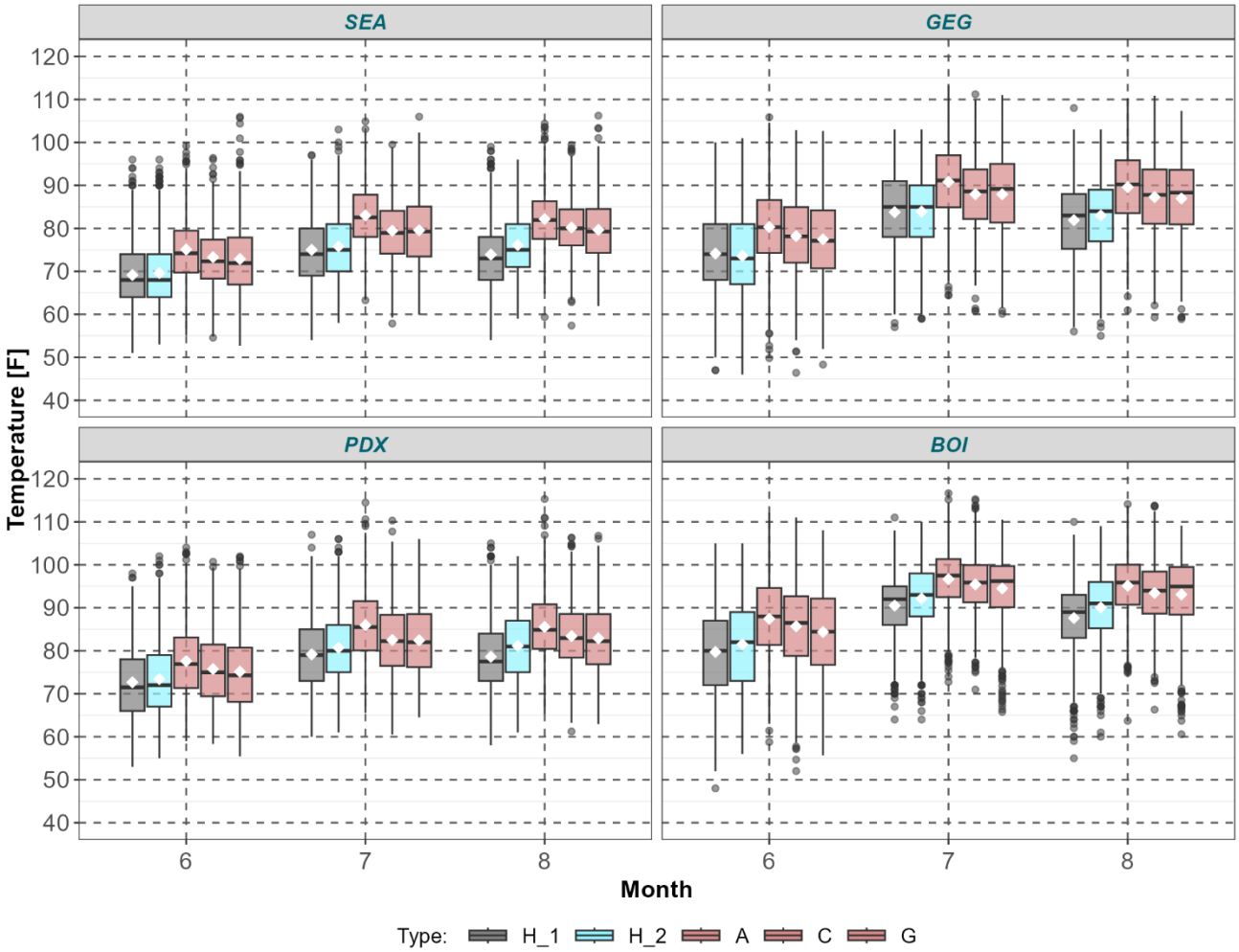
Trends in the Summer Months

Next, the summer months for the Northwest are usually defined as June, July, and August, and loads during these months are generally also the highest. In Figure D - 28 are the boxplots of the distributions of the daily maximum temperatures for the summer months of the two historical sets H_1 (in gray) and H_2 (in light blue), and climate scenarios A, C, and G (in light red), for the four cities.

In Figure D - 28, over all three summer months at all four cities, it is the same overall climate trend of warming temperatures from H_1 to H_2 to the climate scenario years. Therefore, the distribution of cooling degree-days (CDDs) of the climate scenario temperatures will be higher than the distribution of CDDs of the historical temperatures in H_2, which in turn will be higher than the distribution of CDDs of the historical temperatures in H_1. The forecasted loads follow the trends in the CDDs and thus, it could be deduced that the distribution of forecasted loads using the climate scenario temperatures will be higher than that using historical temperatures in H_2 which in turn will be higher than that using historical temperatures in H_1.

Putting summer and winter together, it could be deduced that the distribution of forecasted loads in the climate scenarios will be higher than historicals for the summer months and lower than historicals for the winter months.

Figure D - 28: Distributions of Summer Daily Maximum and Minimum Temperature at the Four Cities



It should be noted that the highest historical temperatures were achieved at GEG at 109 F, PDX at 116F, and SEA at 108 F on several days in and around the 2021 heat dome event. However, historical year 2021 is not among the years in historical data H_1 or H_2. Therefore, these highest historical temperatures for the three cities are not plotted in Figure D - 28. However, a more detailed analysis of very high climate scenario temperatures as plotted in Figure D - 28, and very high historical temperatures from 1948 to 2024, which do include those of the 2021 heat dome, are presented in a subsequent section.

In addition, in Figure D - 28, for each of the three summer months respectively, the distributions of daily maximum temperatures at the near coastal cities, SEA and PDX, are lower than those at the inland cities, GEG and BOI. Furthermore, the aggregate warmings of the daily maximum temperatures for all 12 months in Figure D - 26 are not spread uniformly over the three months in Figure D - 28. The differences of the averages between the five distributions are tabulated in Table D - 13 to Table D - 16 for the four cities. In each of the four Tables, the the highest warming by month in bold text.

Table D - 13: Differences of the Averages of the Daily Maximum Temperature Distributions in [F] for BOI for Months 6, 7, 8

$BOI/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
6	+ 1.7	**+ 6.0**	**+ 4.2**	+ 2.9
7	+ 1.6	+ 4.5	+ 3.3	+ 2.4
8	**+ 2.4**	+ 5.1	+ 3.4	**+ 3.0**

Table D - 14: Differences of the Averages of the Daily Maximum Temperature Distributions in [F] for GEG for Months 6, 7, 8

$GEG/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
6	- 0.5	+ 6.7	**+ 4.6**	+ 3.9
7	+ 0.1	**+ 6.9**	+ 4.1	**+ 4.0**
8	**+ 1.1**	+ 6.6	+ 4.3	**+ 4.0**

Table D - 15: Differences of the Averages of the Daily Maximum Temperature Distributions in [F] for PDX for Months 6, 7, 8

$PDX/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
6	+ 0.8	+ 4.2	**+ 2.3**	+ 1.7
7	+ 1.6	**+ 5.2**	+ 1.8	+ 1.7
8	**+ 2.5**	+ 4.4	+ 2.3	**+ 1.8**

Table D - 16: Differences of the Averages of the Daily Maximum Temperature Distributions in [F] for SEA for Months 6, 7, 8

$SEA/Month$	H_2 vs H_1	A vs H_2	C vs H_2	G vs H_2
6	+ 0.5	+ 5.5	+ 3.7	+ 3.3
7	+ 0.8	**+ 7.2**	+ 3.6	**+ 3.8**
8	**+ 2.2**	+ 6.0	**+ 4.1**	+ 3.5

From H_1 to H_2, the month with the highest warming is August for all four cities. However, from to H_2 to the climate scenario years, there is no set pattern in the city or the month with the highest warming. Nevertheless, over all all three summer months and at all four cities, it is the usual climate trend that climate scenario A has the highest warming and scenario G has the lowest warming.

Trends in the Other Months

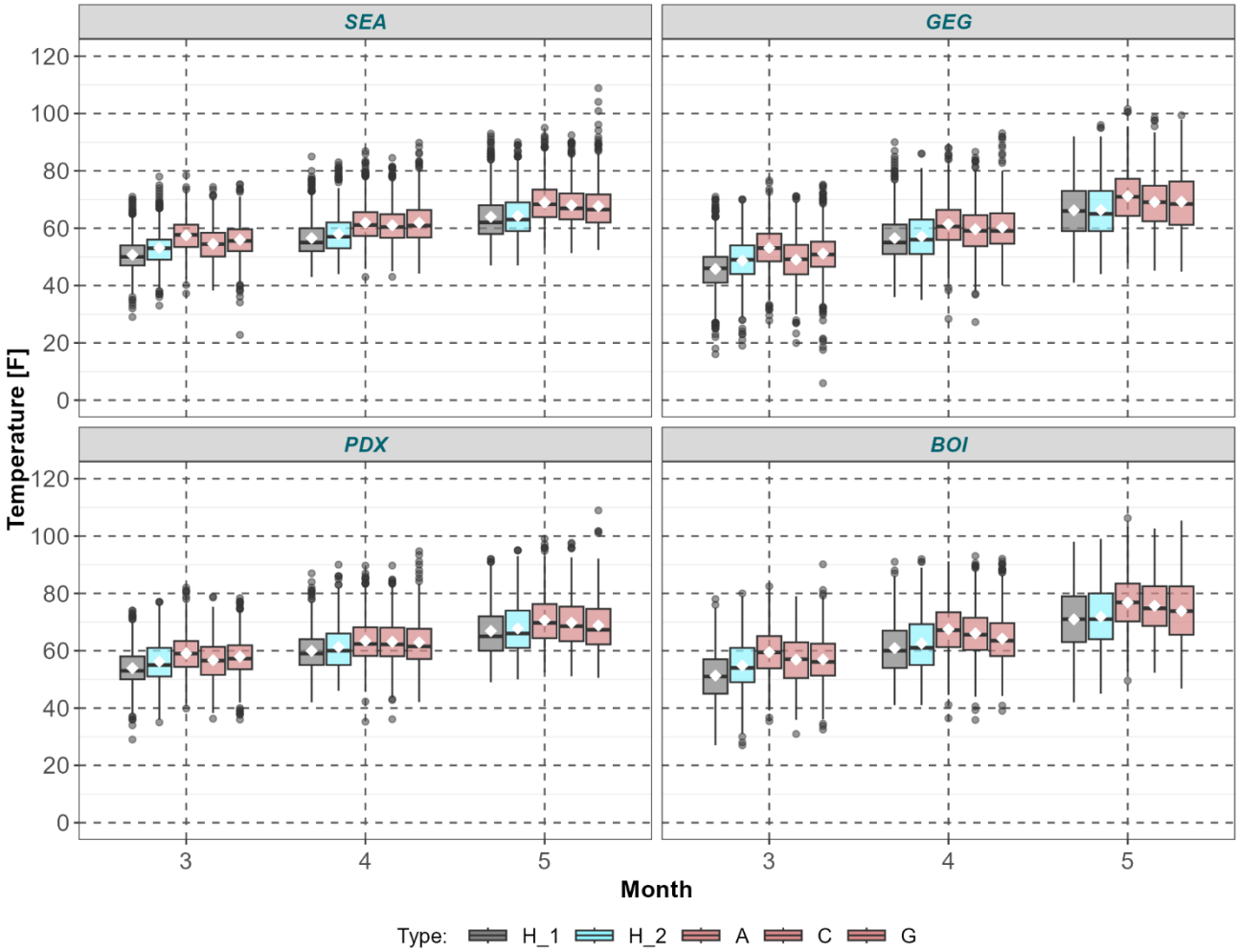
In addition to the winter and summer months are the spring months, from March to May, and the fall months, from September to November. For the spring and fall months, for simplicity, only the daily maximum temperatures are analyzed. Boxplots of the distributions of the daily maximum temperatures at the for cities are plotted for the spring months in Figure D - 29, and for the fall months in Figure D - 30.

For each of the four cities, the distributions of daily maximum temperatures for the spring and fall months plotted in Figure D - 29 and Figure D - 30, are lower than those of the summer months plotted in Figure D - 28, which lead to their CDDs being lower than those of the summer months. On the other hand, their distributions of daily minimum temperatures (not presented for simplicity) are higher than those of the winter months, and thus, their HDDs will be lower than those of the winter months. Because of the lower HDDs than those of winter months and lower CDDs than those of the summer months, it could be deduced that the distributions of the forecasted loads for the spring and fall months will be lower than those for the winter and summer months.

In Figure D - 29 below, over all three spring months at all four cities, is also the overall climate trend of warming from H_1 (in gray boxplots) to H_2 (in light blue boxplots) to the climate scenario years (in light red boxplots). The warmer climate scenario temperatures will lead to lower HDDs and higher CDDs than those of the historical temperatures, which will lead to the forecasted loads for the climate scenarios being lower (than historical) for the cooler days but higher (than historical) for the warmer days.

As discussed previsouly, for the winter and summer months, the warming climate scenario temperatures lead to simple deductions of lower winter loads but higher summer loads when compared to historical winter and summer loads. However, for the spring months, there is not a simple deduction on how climate scenario loads compare to historical loads.

Figure D - 29: Distributions of Spring Daily Maximum and Minimum Temperature at the Four Cities



In general, for the spring months, some of the climate trends are similar to those discussed previously for the winter and summer months:

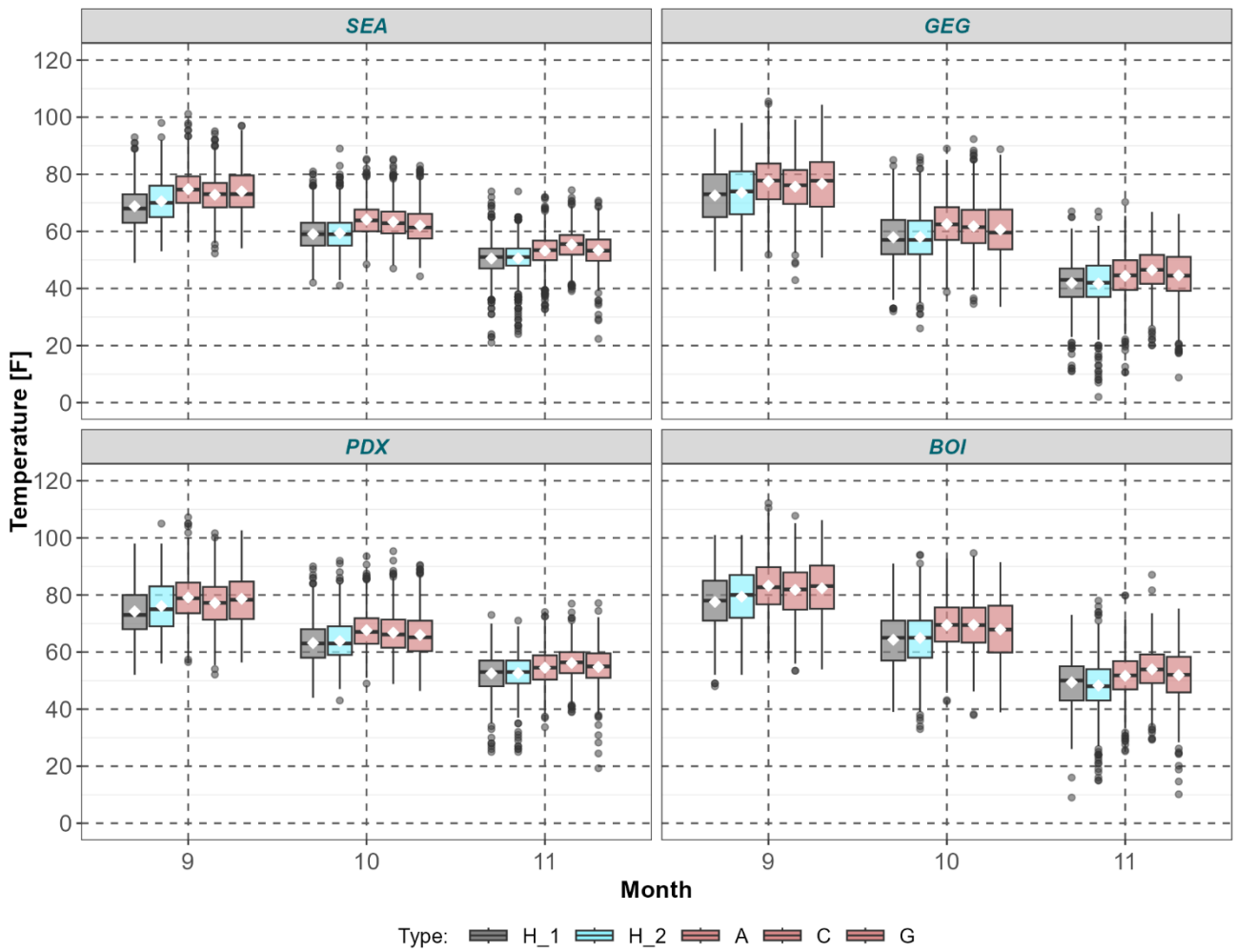
- the temperatures are getting warmer over the years, from H_1 to H_2, and from H_2 to the climate scenario years;
- for the climate scenarios at all four cities, climate scenario A has the highest warming while G has the lowest warming.

Moreover, from H_1 to H_2, the month with the highest warming is March for all four cities. However, from to H_2 to climate scenarios A and C, the month with the highest warming is May. But for scenario G, there is no pattern for the month with the highest warming over the four cities.

It should be noted that for the "shoulder" summer month of May, there are some days where the daily maximum temperatures are at or greater than 100 F at the four cities, and the forecasted loads on these days are expected to be particularly high.

Finally, in Figure D - 30 below, for all three fall months at all four cities, is once again the ovearll climate trend of warming from H_1 (in gray boxplots) to H_2 (in light blue boxplots) to the climate scenario years (in light red boxplots). Following the same analyses as performed for the spring months: the warmer climate scenario temperatures lead to lower HDDs and higher CDDs than those of the historical temperatures, which lead to the forecasted loads for the climate scenarios being lower (than historical) for the cooler days but higher (than historical) for the warmer days. Therefore, for the fall months, there is not a simple deduction how climate scneario loads compare to historical loads, just as for the spring months.

Figure D - 30: Distributions of Fall Daily Maximum and Minimum Temperature at the Four Cities



In general, for the fall months, some of the climate trends are similar to those discussed previously for the winter, summer, and spring months:

- the temperatures are getting warmer over the years, from H_1 to H_2, and from H_2 to the climate scenario years;

- for the climate scenarios at all four cities, climate scenario A usually has the highest warming while G has the lowest warming with one exception: at BOI, it is climate scenario C that has the highest warming.

Moreover, from H_1 to H_2, the month with the highest warming is September. However, for climate scenario A, the month with the highest warming is October, while for scenarios C and G, the month with the highest warming is November.

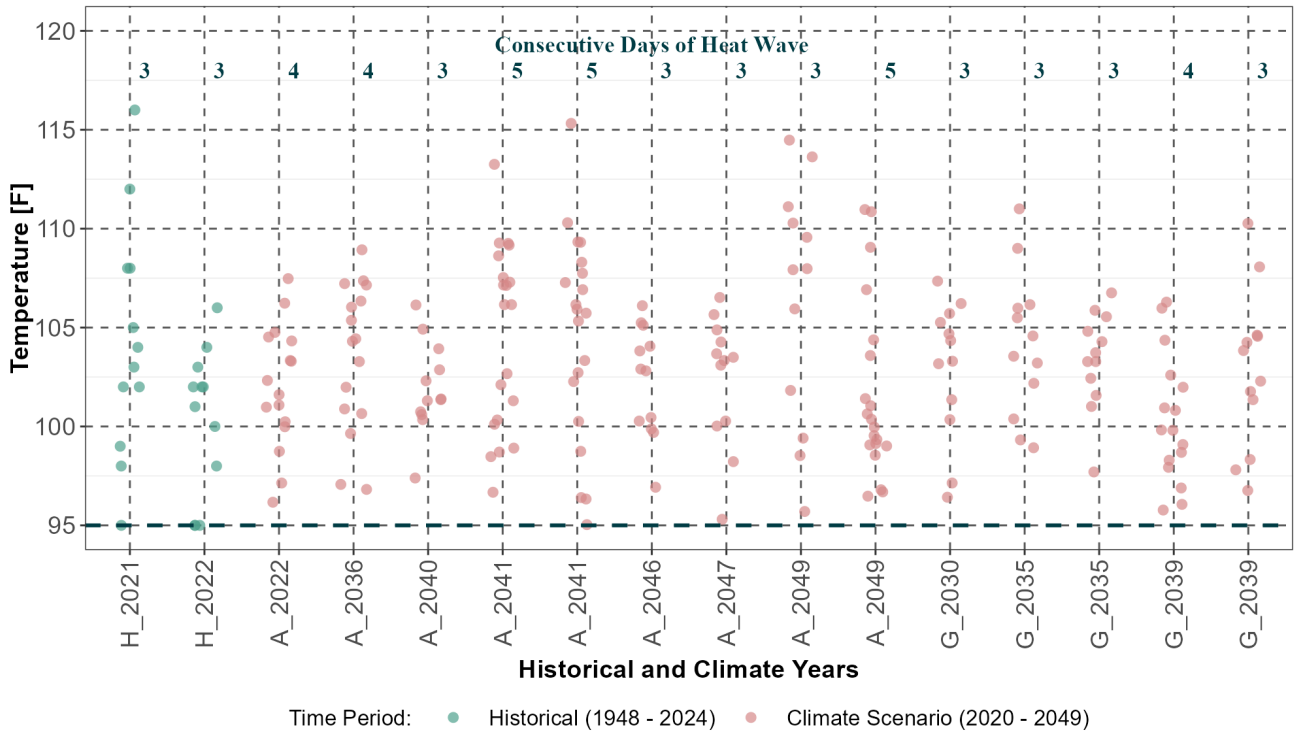
Trends in Cold Snaps and Heat Waves

A regional cold snap or heat wave is generally defined as three or more consecutive days of very low or very high temperatures, respectively, across the region. Since temperatures in coastal areas such as PDX or SEA are milder than those in interior regions such as BOI or GEG, then temperatures that are considered very high or very low in coastal areas might be considered merely high or low in interior regions. Conversely, temperatures that are considered very high or very low in interior regions are likely to be very rare in coastal areas that it is unlikely to have three or more consecutive days of such temperatures there. Therefore, for the entire region, there is not a standard definition of the very low temperatures for a cold snap or the very high temperatures for a heat wave. Nevertheless, for the example very high and very low temperatures defined in this section, the regional power system is likely to be under stress to serve the high loads during the multi-day durations of the cold snaps and heat waves.

This analysis uses temperatures at the four regional population centers: BOI, GEG, PDX, and SEA. The Council defines a regional heat wave as any event where the daily maximum temperatures of all four cities are at or greater than a threshold temperature of 95 F for three or more consecutive days, as there are two historical events in 2021 and 2022 that meet this threshold.

The climate trend of heat waves are presented in Figure D - 31 below, where the historical and climate scenario data are plotted in the green circles and light red circles, respectively. Also, the historical and climate scenario years in which the heat waves occur are listed along the x-axis. More specifically, the two historical heat waves are listed as H_2021 (the heat dome event) and H_2022 at the left side of the figure. In contrast, there are 14 climate scenario heat waves starting with A_2022, representing climate year 2022 of climate scenario A, and ending with G_2039, at the right side, representing climate year 2039 of scenarion G. Also, it could be seen that there are two heat waves for climate years 2041 and 2029 of scenario A, and climate year 2039 of scenario G.

Figure D - 31: Daily Heat Wave Maximum Temperatures at Four Cities

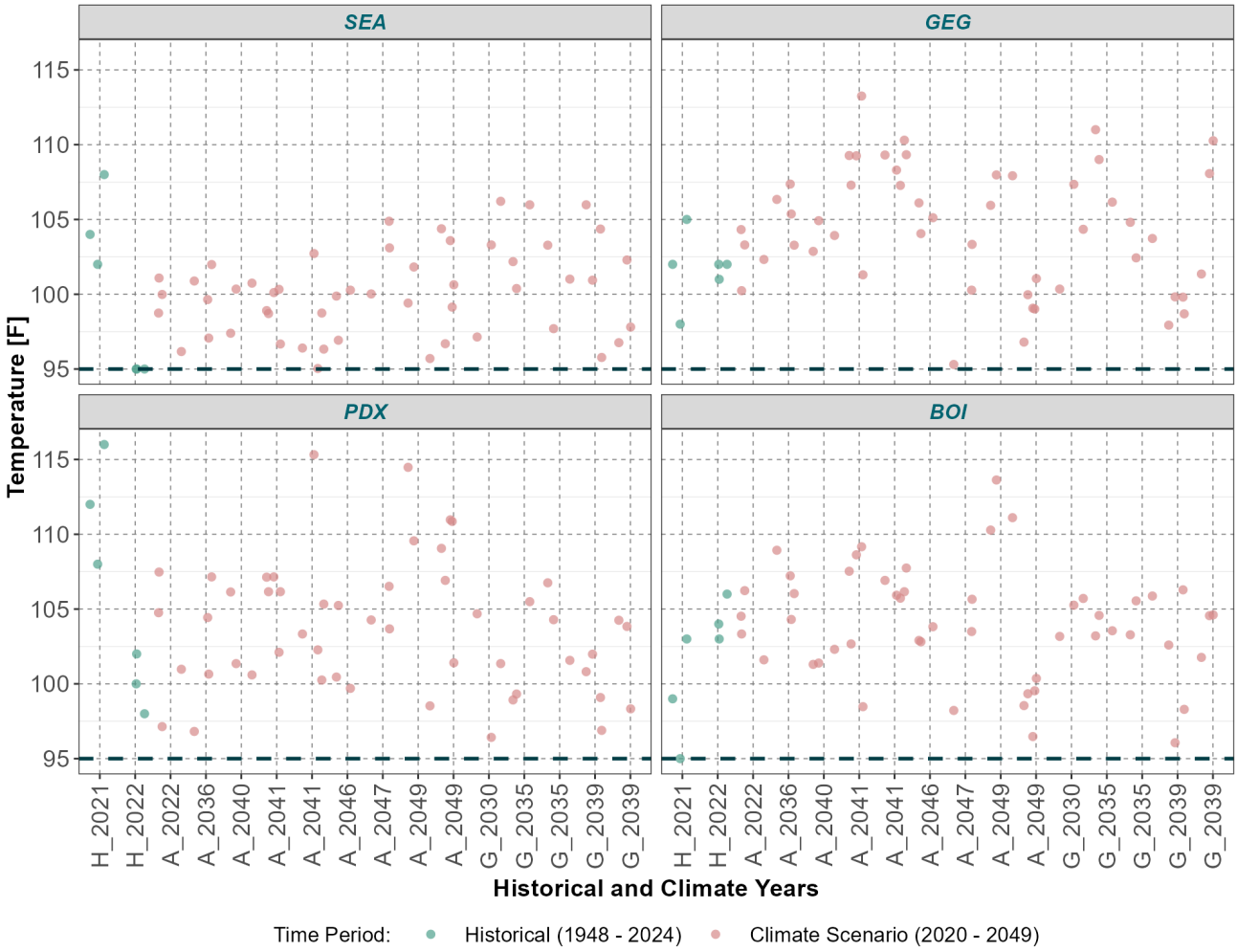


In Figure D - 31, the durations of the heat waves are listed in the dark green numbers near the top. For example, for the H_2021 heat wave at the left side, the duration was three consecutive days. Therefore, the daily maximum temperatures at the four cities for the three days are plotted in 12 green circles, with one at 95 F, which is the heat wave threshold temperature, plotted in the horizontal dark green dashed line. There are three climate scenario heat waves with longer durations of five consecutive days: the two in A_2041 and the second in A-2049. For these, there are 20 light red circles plotted.

The climate trend in Figure D - 31 is clear: there are many more heat waves in the climate scenario years, totaling 14, than in the historical years, totaling two. In addition, many of the climate heat waves have longer durations. However, for a fair comparison of the number of heat waves, the populations of the two data sets should be the same. But in this analysis there are more years of climate scenario data (90) than years of historical data (77), which leads to the population of climate data having a ratio of $90/77 \cong 1.17$ relative to the population of historical data. In other words, the climate data is about 17% larger than the historical data, and thus, the number of heat waves in the historical data should be adjusted due to the smaller population of the historical data. For a very rough estimate, increasing the population of the historical data by 17% should increase the number of heat waves to $(1.17) \times 2 = 2.34$. However, even with the population adjustment, there are still many more heat waves in the climate scenario years than in the historical years.

Next, it is useful to disaggregate temperatures at the four cities, which leads to Figure D - 32 below.

Figure D - 32: Daily Heat Wave Maximum Temperatures at Four Cities



In Figure D - 32, the SEA heat-wave temperatures are plotted in the top left panel. It could be seen that they are, as a distribution, lower than those of the other three cities plotted in the remaining panels. There are only five days where the SEA temperatures are at or above 105 F compared to the many more days in the other three panels. Furthermore, for all three days of the H_2022 heat wave, the SEA daily maximum temperatures were at 95 F, the heat wave threshold temperature. In addition, there are no climate scenario heat-wave temperatures higher than highest historical temperature of 108 F during the 2021 heat dome. However, for temperatures outside of heat-waves, there is one climate scenario temperature slightly higher than 108 F.

Furthermore, for the PDX (bottom left panel) heat-wave temperatures, there are two climate scenario temperatures, in years 2041and 2049 of climate scenario A, that are just slightly below the highest historical temperature of 116 F during the 2021 heat dome. For temperatures outside of heat-waves, there is no climate scenario temperature higher than the highest historical temperature of 116 F.

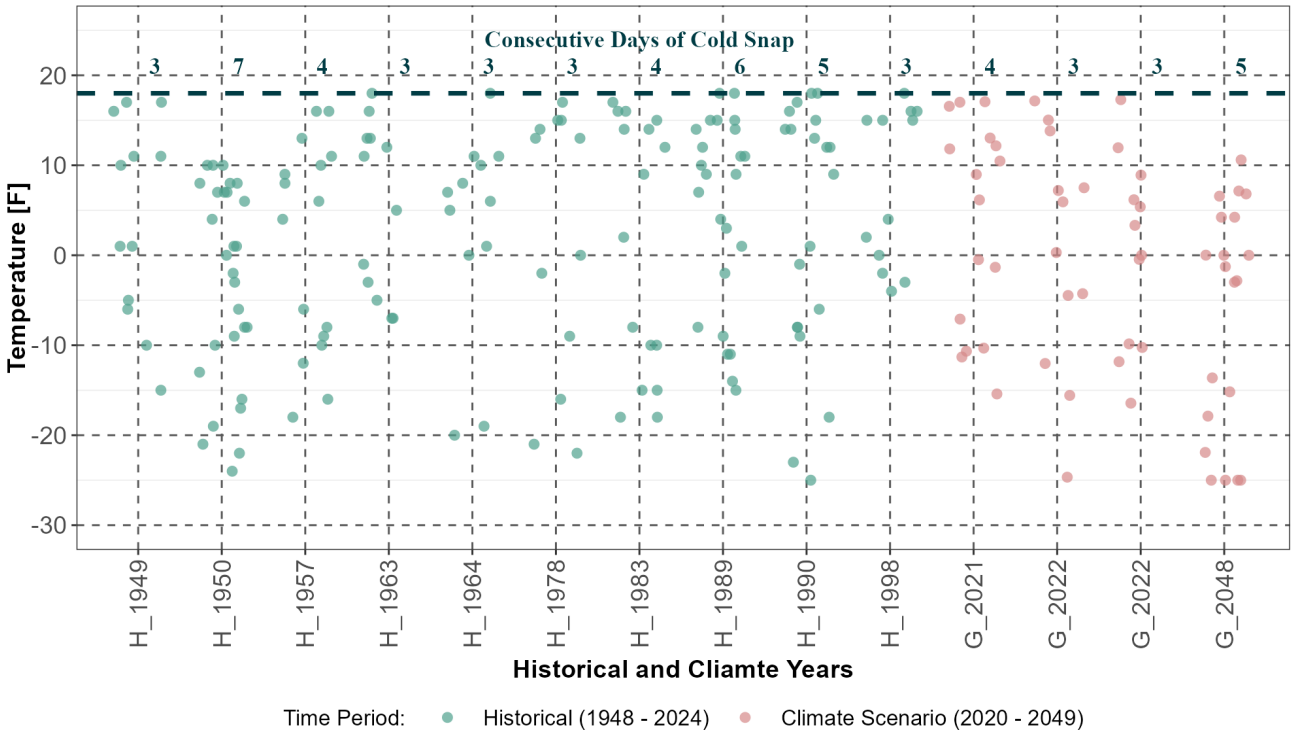
In addition, for the inland cities, BOI (bottom right panel) and GEG (top right panel), there are many climate scenario heat-wave temperatures significantly higher than the historical heat-wave temperatures as plotted in Figure D - 32. Outside of temperatures during heat-waves, the highest

historical temperatures at BOI and GEG were 111 F and 109 F, respectively. It should be noted the 109 F GEG temperature occurred on the day after the historical 2021 regional heat-wave ended. On that same day, the PDX and SEA temperatures were at 93 F and 85 F, respectively, which were below the threshold heat-wave temperature of 95 F. There are 41 and 24 climate scenario daily maximum temperatures higher than the highest historical temperature at BOI (111 F) and GEG (109 F), respectively.

Next, cold snaps are analyzed. For this analysis, the Council defined a cold snap as any event such that the daily minimum temperatures of all four cities are at or lower than a threshold temperature of 18 F for three or more consecutive days.

The climate trend of cold snaps is presented in Figure D - 33 below, where the historical and climate scenario data are plotted in the green circles and light red circles, respectively. Also, the historical and climate scenario years in which the cold snaps occur are listed along the x-axis. More specifically, there were 10 historical cold snaps compared to four climate scenario cold snaps all from scenario G.

Figure D - 33: Daily Cold Snap Minimum Temperatures at Four Cities



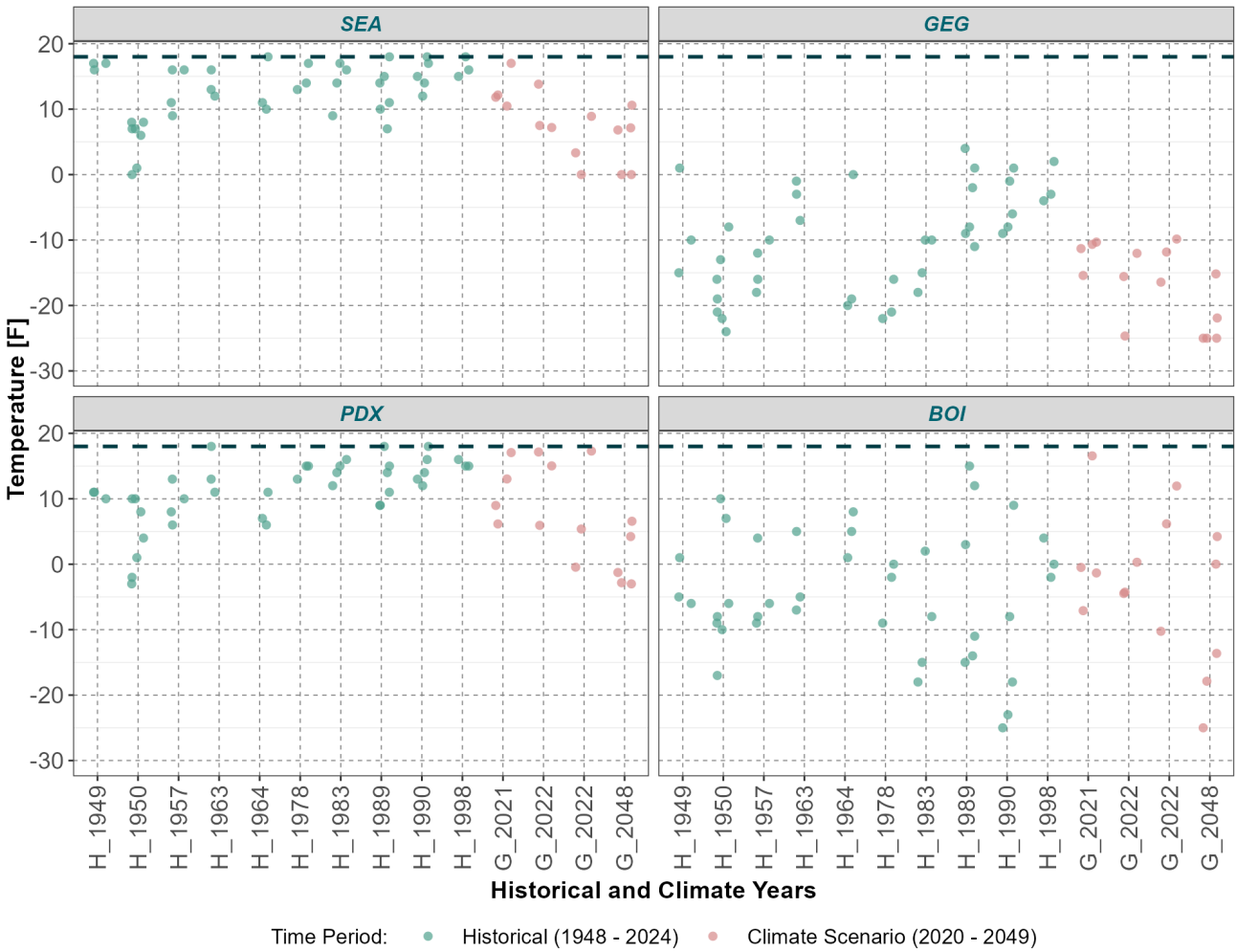
In Figure D - 33, the durations of the cold snaps are listed in the dark green numbers listed near the top. For example, during the H_1950 cold snap near the left side, the duration was very long and lastedseven consecutive days. Therefore, the daily minimum temperatures at the four cities for the seven days are plotted in 28 green circles, where most of them are at or below 10 F. The longest duration of a climate scenario cold snap is five consecutive days, in G_2048. The cold snap daily minimum threshold temperature of 18 F is plotted in the horizontal dark green dashed line.

It should be noted in January 2024, there were five consecutive days with very cold temperatures at the four cities. However, among the five days, there were three days at PDX and SEA with daily minimum temperatures higher than the threshold temperature of 18 F. Thus, this cold event in 2024 is not a cold snap as defined in this analysis.

The climate trend presented in Figure D - 33 is also clear, namely, there are fewer cold snaps in the climate scenario years than in the historical years: four versus ten. However, the number of cold snaps in the historical years should be adjusted due to the historical data being 17% smaller than the climate data. Therefore, the adjusted number of historical cold snaps is $(1.17) \times 10 \cong 11.7 \approx 12$ which is even higher than before, being nearly 3 times the number of climate scenario cold snaps.

Finally, disaggregating temperatures in Figure D - 33 into those at the four cities result in Figure D - 34 below.

Figure D - 34: Daily Cold Snap Minimum Temperatures at Four Cities



In Figure D - 34, the SEA and PDX cold snap temperatures are plotted in the top left panel and bottom left panel respetively. As distributions, they are significantly higher than those at GEG and BOI. There are no days below 0 F at SEA, and only six days slightly below 0 F at PDX. It should be noted that the

climate scenario temperatures have been adjusted such that at each city, those that are below its lowest historical temperature have been set equal to the lowest historical temperature.

Thus, in the climate scenario years, there are fewer cold snaps but many more heat waves (than in the historical years) during which the regional power system would be under stress to serve these very high loads.

Climate Scenario Wind Generation Profiles

As discussed in a previous section, climate scenario wind speed data are not included in the RMJOC data sets; fortunately, wind data from compatible scenarios are available from the Climatology Lab (CL) at the University of California, Merced.[63]

The climate models and downscaling methods of the three selected RMJOC climate scenarios A, C, and G are listed in the left column of Table D - 17 below. It's evident that the BCSD downscaling method was used to develop A and C while MACA was used to develop G. Unfortunately, all climate scenarios from the Climatology Lab (CL) were developed using MACA, as shown in the right column of Table D - 17. Thus, CL has an exact match for scenario G that also used MACA. However, there is not an exact match for either A or C. Nevertheless, since both the RMJOC and CL scenarios originate from the same climate models, it is assumed here that differences between the RMJOC and CL scenarios are small.

Even though the Climatology Lab Scenarios for the CanESM2 and CCSM4 GCMs are not exactly the same as RMJOC scenarios, for simplicity, they will still be referred to as A and C, respectively, in subsequent sections.

Table D - 17: Selected RMJOC Climate Scenarios and Compatible Climatology Lab Scenarios

RMJOC Scenarios	Climatology Lab Scenarios
A: CanESM2_RCP85_**BCSD**	CanESM2_RCP85_**MACA**
C: CCSM4_RCP85_**BCSD**	CCSM4_RCP85_**MACA**
G: CNRM-CM5_RCP85_**MACA**	CNRM-CM5_RCP85_**MACA**

The downloaded CL scenario daily average wind speeds undergo further calculations that result in a set of future hourly wind generation at various locations considered as in-region for the Ninth Plan, which then become inputs into the Council's models. The details are described in this section.

[63] Climatology Lab: *https://www.climatologylab.org/maca.html*.

In-Region Wind Fleets

For the Ninth Plan, the Council used five in-region locations to develop wind generation profiles[64] plotted in Figure D - 35 below.

Figure D - 35: In-Region Wind Fleet Generation Locations for the Ninth Plan

For simplicity, the five simulated wind fleets at the Gorge, Southeast Washington, Idaho, Montana, and Wyoming are abbreviated as GO, WA, ID, MT, and WY, respectively. In addition, the latitude and longitude coordinates of the five wind fleet locations are listed in Table D - 18.

Table D - 18: The Five In-Region Wind Fleet Generation Locations

Locations	Latitude	Longitude
The Gorge (GO)	45.601	-120.602
Southeast Washington (WA)	46.399	-117.578
Idaho (ID)	43.320	-112.007
Montana (MT)	47.166	-110.501
Wyoming (WY)	41.683	-107.200

[64] See Technical Appendix G - New Generating Resources in the Ninth Power Plan for more details.

CL Scenario Wind Speed Data

The CL scenario wind data are at 10-m height ("near-surface") and need to be extrapolated to two hub-heights, 80-m and 100-m, for wind turbine models GE 1.5 SLE and Vestas v112-30, respectively, that were selected for the simulations in the Power Plan. The extrapolation formulas analyzed were taken from the chapter "*Methodologies Used in the Extrapolation of Wind Speed Data at Different Heights and Its Impact in the Wind Energy Resource Assessment in a Region*" by Bañuelos-Ruedas et al. in the book *Wind Farm - Technical Regulations, Potential Estimation and Siting Assessment* (DOI: 10.5772/20669). The authors presented several formulas that relate wind speeds at different heights under certain conditions. One of the formulas is the exponential law:

$$\frac{V_2}{V_1} = \left[\frac{H_2}{H_1}\right]^{\alpha}$$

where V_1 and V_2 are the wind speeds at heights H_1 and H_2 respectively, and α is the friction coefficient or the Hellman exponent. The equation above has a slightly different expression than the one in the reference material. Since many existing wind turbines are located around farmlands, values for α could be selected based on landscape types listed in Table 1 in the reference. For example, $\alpha = 0.15$ for grasslands, while $\alpha = 0.2$ for tall crops, hedges and shrubs. In addition, a commonly used value for α is $(1/7) \approx 0.143$.

Another formula presented in the reference is the logarithmic law:

$$\frac{V_2}{V_1} = \frac{ln\left[\frac{H_2}{H_0}\right]}{ln\left[\frac{H_1}{H_0}\right]}$$

where H_0 is the roughness coefficient length, in meters. Similarly, the equation above has a slightly different expression than the one in the reference. To model wind turbines around farmland, the landscape type "*farming land dotted with some houses and 8-meter-tall sheltering hedgerows within a distance of some 1,250 meters*" was selected from Table 4 in the reference with a corresponding coefficient $H_0 = 0.055$ meters.

Let V_1 represent the CL scenario wind speeds at 10-m height, then $H_0 = 10$ meters. In Figure D - 36 below are plots of the ratio (V_2/V_1) on the y-axis as a function of height H_2 (in meters) on the x-axis. The two green curves represent the exponential law with parameter $\alpha = 0.2$ for the upper dotted curve and $\alpha = (1/7)$ for the lower dashed curve. The light red curve represents the logarithmic law with parameter $H_0 = 0.055$ meters.

Figure D - 36: Wind Speed Ratio vs Height

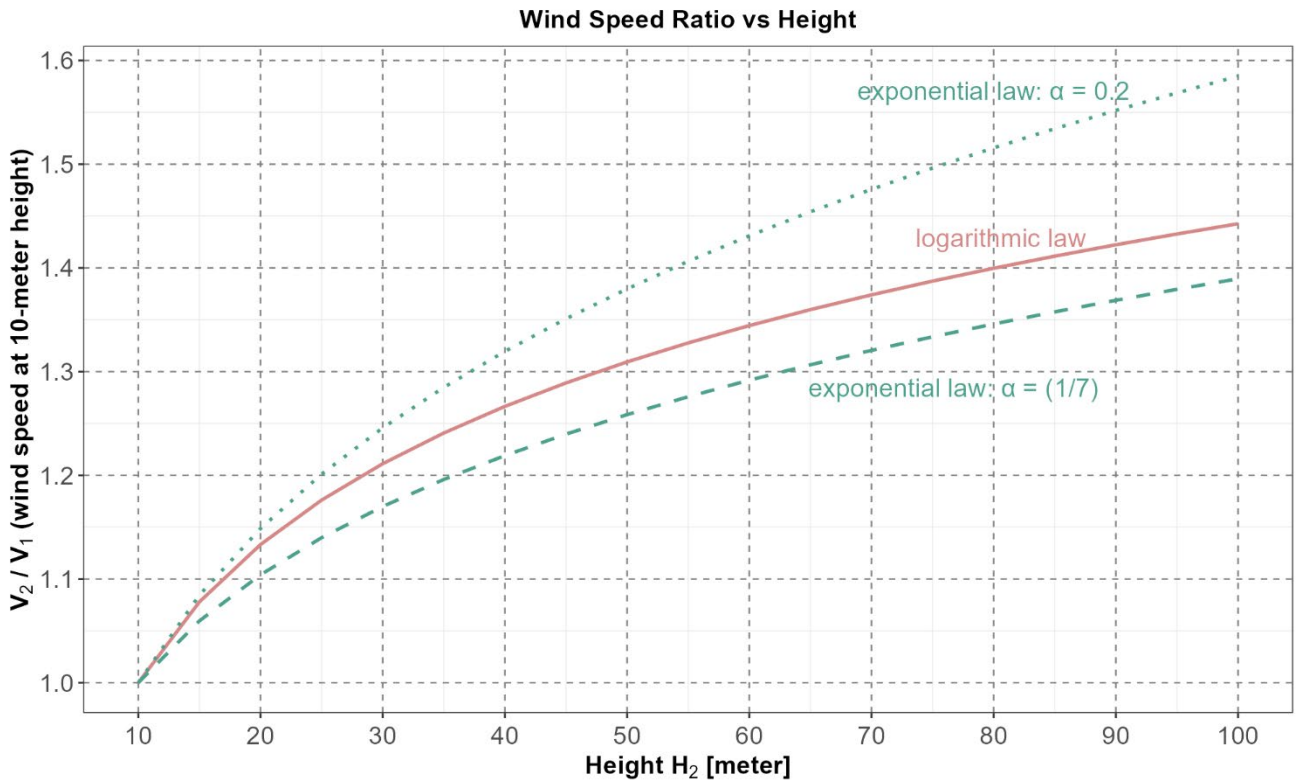


Figure D - 36 shows that all three wind speed ratios start correctly at 1 at a height of 10 meters. For the logarithmic law, the 80-meter and 100-meter wind speeds are respectively 40% and 44% higher than the 10-meter wind speed. Because the log-function increases more slowly for larger values, the 100-meter wind speed is only 3% higher than the 80-meter wind speed. All three curves are relatively close together in the Figure: the upper and lower green curves are about 9% higher and 4% lower, respectively than the red curve for $H_2 = 80$ meters and 100 meters. For simplicity, the red curve, or the logarithmic law, is used to extrapolate climate scenario wind speeds at a 10-meter height to wind speeds at 80 meters and 100 meters, which are then used to simulate wind fleet generation in the Ninth Plan.

However, before using the climate wind data, it should be reminded that in developing the downscaled climate scenario streamflow data for the Northwest region, the RMJOC had to perform bias-corrections in the process.[65] The bias-corrections are developed to transform the climate scenario wind data to resemble historical data in a common historical time period.

[65] *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

The climate data used in the Power Plan covers the 30 water-years from 2020 to 2049, or 31 calendar years from 2019 to 2049 (except for several months). The historical data set, the ERA5[66] 100-m wind speed data, are available for years from 1980 to 2018 in the renewable energy simulation model, Time Series Lab (TSL).[67] Therefore, the CL climate 100-m wind data are bias-corrected to resemble the ERA5 100-m wind speed data for the common 31 historical years from 1988 to 2018. However, it turns out that even the ERA5 data themselves require bias-corrections which are discussed in the next section.

The TSL model can be used to generate historical re-analysis data for any coordinate available in the ERA5 datasets, for both wind and solar resources. While a feature of TSL is the ability to extract the embedded ERA5 data (for years 1980 to 2023) for given coordinates and resource types, its main feature is generating historical and future synthetic hourly capacity factors (CFs). The TSL model output of hourly CF profiles for a set of years are then used as inputs in the Council's production-cost model and capital-expansion model to calculate the shares of wind and solar resources in generation portfolios.

The ERA5 Wind Data

The ERA5 wind dataset covers the years from 1940 to the present. It is a blend of observed data (if they are available), and synthetic data calculated using re-analysis (if observed data are not available). However, even the historical ERA5 data needed to be bias-corrected before being used in the Power Plan. The details are discussed in this section.

Although the ERA5 data is widely used, it can contain forecast errors and biases due to different weather modeling errors. Furthermore, the spatial resolution of 0.25 by 0.25 degrees of latitude and longitude in ERA5 data may not fully distinguish finer topography at a particular location. And lastly, different wind and solar-related meteorological observations may have their own data collection sensitivity and limitations. All these factors lead to systemic errors that could result in overestimation or underestimation of capacity factors. A study examining ERA5-derived capacity factors across the continental United States found that broadly, ERA5-derived solar CFs may be biased high, and wind CFs biased low.[68] For example, in winter, the ERA5 solar CF is on average 23% higher than observed data, while annually, ERA5 wind CF is 20% lower than observed data.

To mitigate the inherent biases in ERA5 data, TSL uses observed or "better" synthetic CF data to generate bias-correction profiles. These correction profiles force the average of the distribution of the ERA5 CFs to align with the average of the correction profiles. The correction profiles can be annual

[66] The ERA5 historical climate data is developed by the Copernicus Climate Change Service at the European Centre for Medium-Range Weather Forecasts (ECMRW). See https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5 for more details.
[67] See https://www.timeserieslab.com for more details.
[68] See https://www.mdpi.com/1996-1073/17/7/1667.

(single value, expected annual CF), monthly (12 values, expected CF for each month), or hourly (288 values, the expected hour in a day in every month).

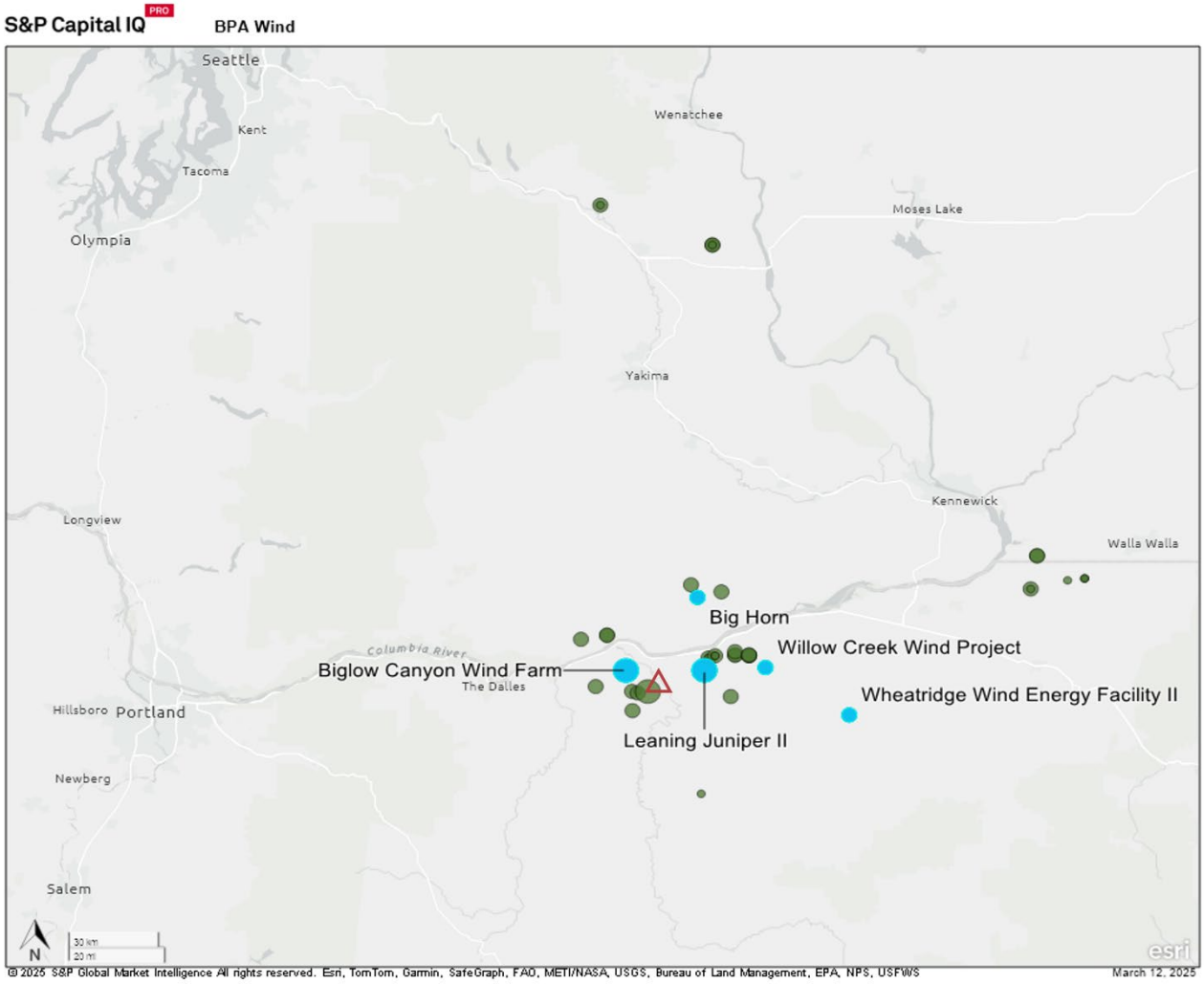
For the five in-region wind fleet locations (GO, WA, ID, MT, and WY), their hourly bias correction profiles are based on available historical synthetic wind speed data at 100-m hub height for years 2007-2014 from the National Wind Toolkit developed by the National Laboratory of the Rockies (NLR).[69] For selected wind turbine types, their wind CFs are then calculated by the NLR System Advisor Model (SAM)[70,71] which are then used by TSL[72] to bias-correct the ERA5 wind CFs and wind speeds at 100-m hub height.

The bias-corrected ERA5 100-m wind data resemble the corresponding NLR 100-m wind data at the five wind fleet locations plotted in Figure D - 35 and listed Table D - 18. The bias-corrected ERA5 80-m wind data are calculated from the ERA5 100-m data using the logarithmic law formula discussed in the previous section. For simplicity, these bias-corrected ERA5 wind data in subsequent sections will be referred to as just the ERA5 wind data.

Since the NLR data themselves are also synthetic, it would be prudent to assess how well the bias-corrected ERA5 data compare with any available observed historical data. Fortunately, there are some observed historical wind generation data around the Gorge area available from the Bonneville Power Administration (BPA).[73] The wind generation data tabulated by BPA is from a collection of wind farms within its balancing area which are plotted in Figure D - 37 below.

[69] The National Laboratory of the Rockies is formerly known as the National Renewable Energy Laboratory. Its Wind Toolkit is: https://www.nlr.gov/grid/wind-toolkit.
[70] NLR's System Advisor Model: https://sam.nlr.gov.
[71] See Technical Appendix G - New Generating Resources in the Ninth Power Plan for more details.
[72] Reference the TSL manual.
[73] See https://transmission.bpa.gov/Business/Operations/Wind.

Figure D - 37: BPA Wind Generation[74]



The wind farms in the BPA BA are plotted in the blue and green circles where a few are widely spread out in Figure D - 37. In contrast, the climate scenario wind data at "The Gorge," one of the five representative wind fleets used in the Ninth Power Plan, is at a single location, plotted in the red triangle.

The various wind farms in BPA's BA were developed over 25 years starting from 1998 to 2022, and their aggregate nameplates are listed in Table D - 19.[75] It should be noted that a few wind farms left the BPA BA between 2014 and 2022, and thus in the Aggregate Nameplate column in Table D – 19, the 2022 aggregate nameplate is less than the 2014 aggregate nameplate.

[74] S&P Global Database for 2025.
[75] See https://transmission.bpa.gov/Business/Operations/Wind/Solar_and_Wind_Nameplate_LIST.pdf.

Table D - 19: Aggregate Namplate Wind Generation in the BPA BA

Year	Aggregate Nameplate (MW)
1998	25
2006	721
2007	1,303
2014	4,782
2022	2,827

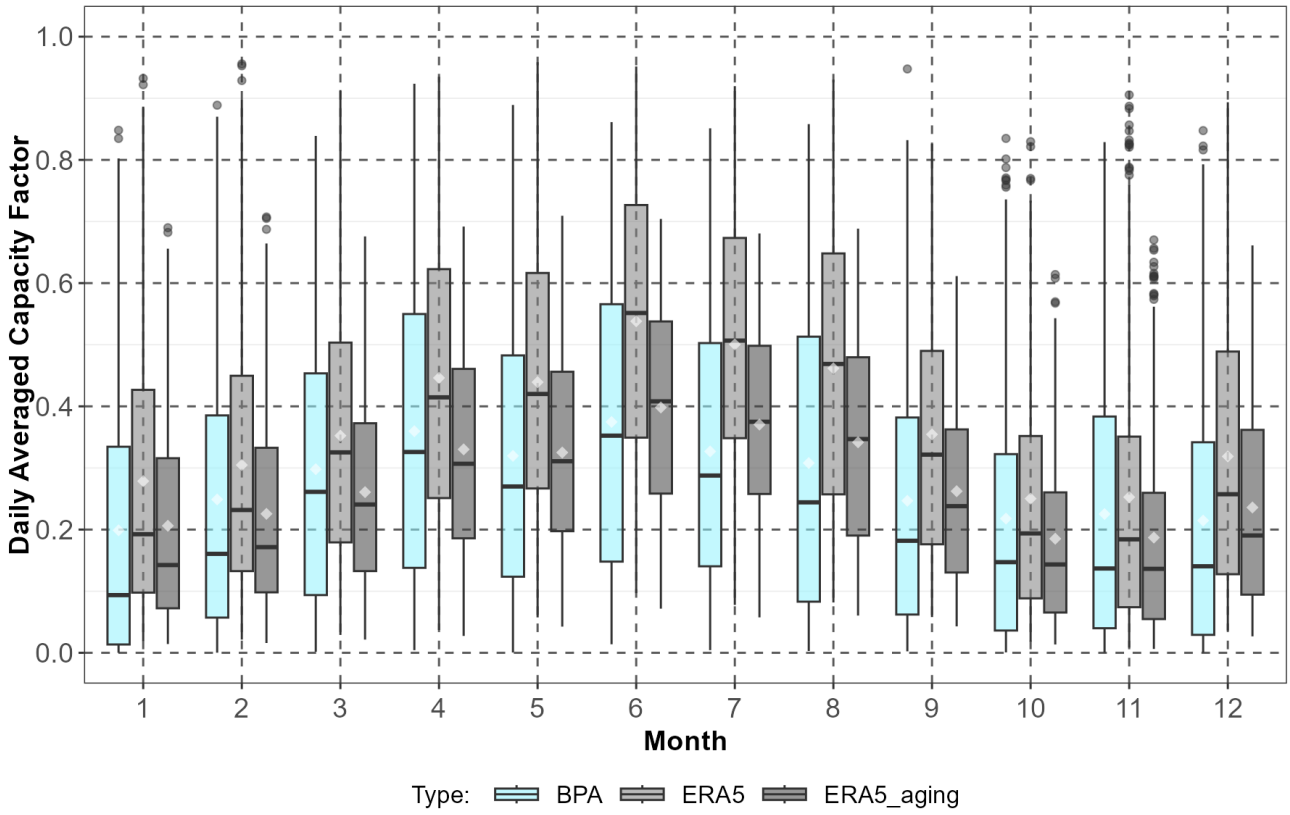
Many of the wind turbines in the various wind farms in the BPA BA were developed over the 25 years and are of different technology types and have different ages where turbines of higher ages would be less efficient in generation.[76]

The BPA aggregated wind generation capacity factors (CFs) are available from 2007 to 2024.[77] For the bias-corrected ERA5 historical wind data from 1988 to 2018, their generation CFs are calculated by the TSL model using the reference 80-m wind turbine GE 1.5 SLE,[78] which by default has no aging effect.

In Figure D - 38 below are comparisons of the distributions of capacity factors (CFs) by month between the BPA (in the light blue boxplots), historical ERA5 (light gray boxplots), and historical ERA5 with aging turbines (medium gray boxplots) for the years they have in common, from 2007 to 2018. CFs of the ERA5 with aging turbines are calculated by multiplying the CFs of ERA5 by a roughly estimated aging factor of 0.74 to reflect BPA wind turbines having higher ages and older technology. The factor 0.74 is the ratio of average BPA CF to average ERA5 CF, where the averages are calculated from their corresponding entire (or annual) distributions.

[76] See the article "*How does wind farm performance decline with age?*" in Renewable Energy 66 (2014) 775 – 786
[77] See https://transmission.bpa.gov/Business/Operations/Wind
[78] See Technical Appendix G - New Generating Resources in the Ninth Power Plan for more details.

Figure D - 38: Comparison of Bonneville and ERA5 Daily Average Wind Capacity Factors



It seems that with the aging factor applied to the ERA5 CFs, their monthly distributions, plotted in the medium gray boxplots, are comparable to the BPA monthly distributions, plotted in the light blue boxplots. Furthermore, both BPA and ERA5 distributions share the seasonal shapes of having higher spring and summer CFs and lower fall and winter CFs.

For the four remaining wind fleet locations, WA, ID, MT, and WY, (see Figure D - 35 and Table D - 18), there is no publicly available observed wind data for comparison to the bias-corrected ERA5 wind data. Therefore, there is no further modification to the bias-corrected ERA5 wind data at the four locations.

Bias-Corrections of the Extrapolated CL Wind Data to the ERA5 Wind Data

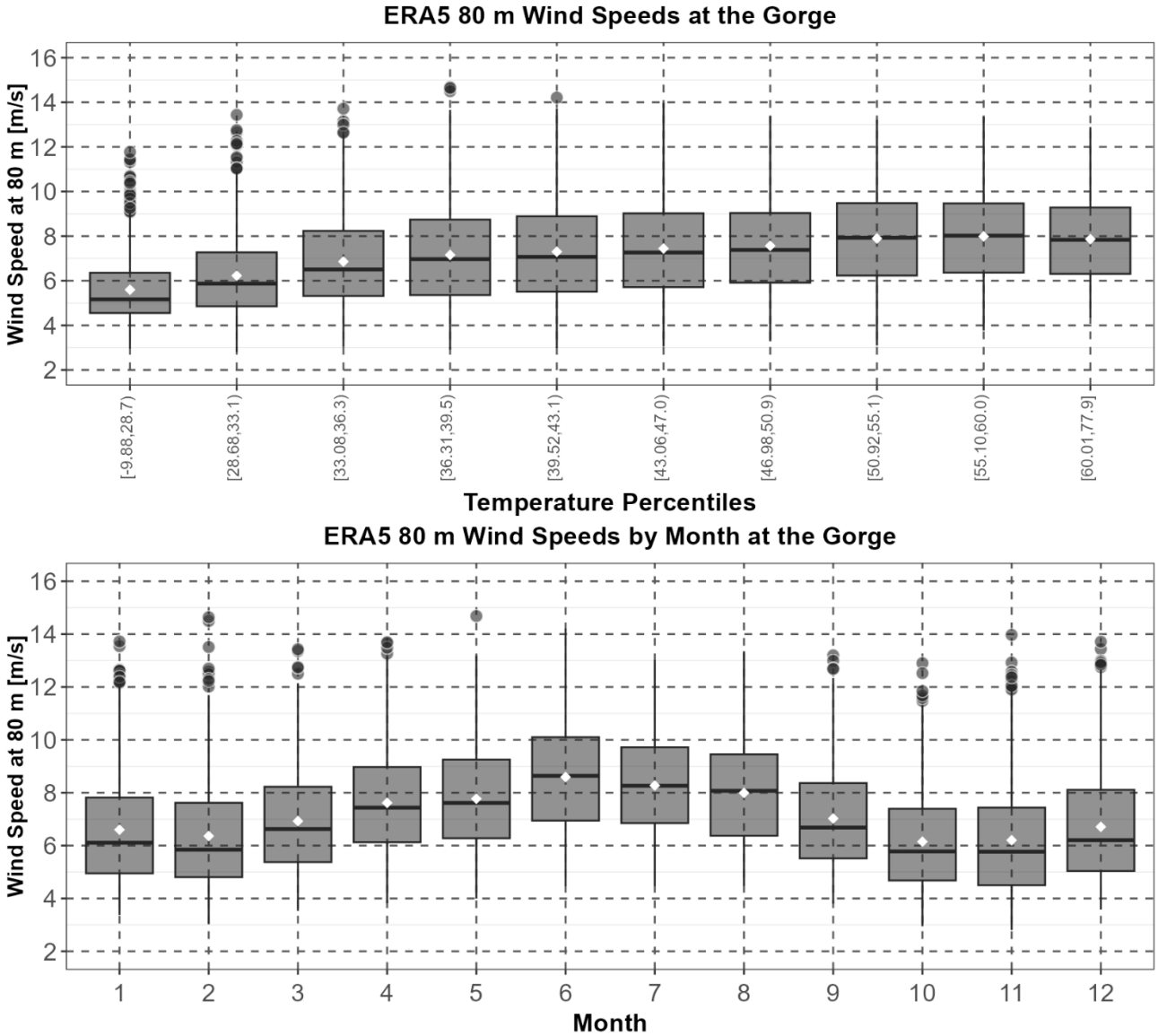
There are 30 different bias-corrections of the CL climate 80-m and 100-m wind data to resemble the corresponding historical ERA5 80-m and 100-m wind data, respectively. The number of bias-corrections result from taking all combinations of the two hub-heights, five wind fleet locations, and the three climate scenarios. However, for simplicity, bias-corrections for the combination of only the 80-m hub-height, the Gorge location, and climate scenario A are presented in this section since bias-corrections for the remaining 29 combinations follow the same processes.

At the Gorge, it has been observed that for some consecutive very cold days or very warm days, wind speeds were very low, leading to lower wind generation. Moreover, if the very cold or very warm temperatures are widespread throughout the region, then the loads were also very high. These periods with very high loads but very low wind are challenging for the power system. Therefore, it is important that in the common historical years, 1988 to 2018, the CL climate wind-temperature correlations resemble those correlations in the historical ERA5 data.

Furthermore, at the Gorge, it has also been observed that the monthly wind speeds have seasonal patterns: higher during late spring and summer months, but lower during late fall and winter months. The CL wind data from 1988 to 2018 should also follow similar seasonal patterns as exhibited in the ERA5 wind generation data in Figure D - 38.

As an example, in Figure D - 39 below, at the Gorge, for the historical years 1988 to 2018, the 80-m ERA5 wind and temperature correlations are plotted in the top panel, and the wind seasonal shapes are plotted in the bottom panel.

Figure D - 39: ERA5 Wind Speed and Temperature Data at the Gorge



For the ERA5 wind-temperature correlations data plotted in the top panel in Figure D - 39, along the x-axis, the daily minimum temperature (a part the ERA5 climate data set embedded in the TSL model) distribution at the Gorge for 1988 to 2018 has been divided into ten equal population percentile subsets. For example, the lowest 10th percentile of the temperature distribution is inside the interval [-9.88 F, 28.7 F). On the other hand, the highest 10th percentile is inside the interval [60.01 F, 77.9 F]. The remaining eight sorted percentile subsets are in between the lowest and the highest percentile subsets. These ten percentile groups of daily minimum temperatures are plotted along the x-axis.

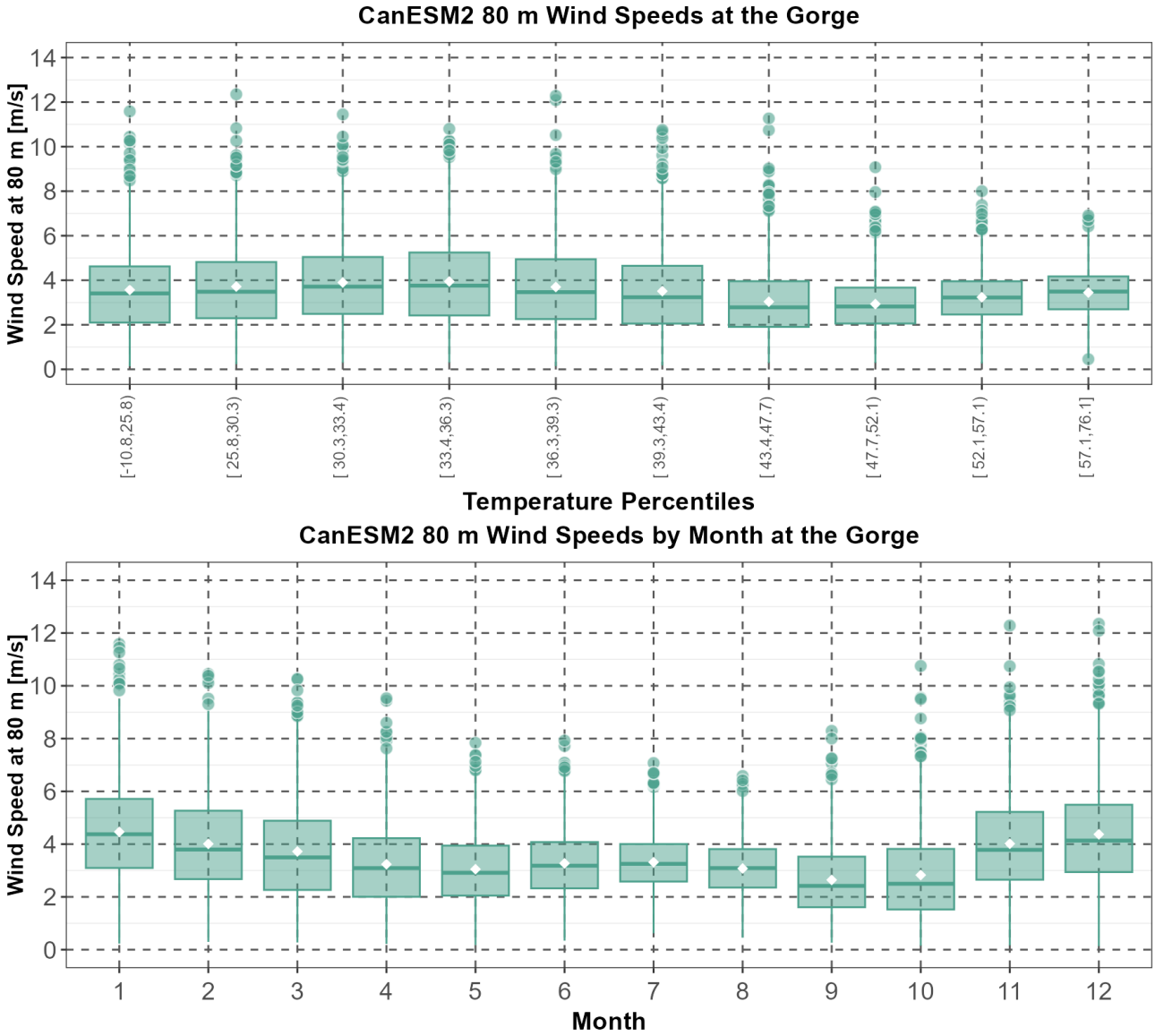
It is quite clear from the wind-temperature correlation plot that wind speeds for the lowest 10th percentile temperatures (at the left most boxplot) are significantly lower than the other percentile groups. On the other hand, it does not seem that wind speeds for the highest 10th percentile temperatures (at the right most boxplot) are lower than adjacent percentile groups.

For the ERA5 monthly wind speed distributions plotted in the bottom panel, the seasonal patterns are clear: higher wind speeds for late spring to summer months, and lower wind speeds for late fall to winter months.

For climate scenario A whose GCM is CanESM2, the 10-m wind speed and temperature at the Gorge were both downloaded from Climatology Lab[79] for historical years 1988 to 2018, and climate scenario years 2019 to 2049 for the Power Plan. As comparisons to the ERA5 data in Figure D - 39, the extrapolated 80-m wind and temperature correlations for climate scenario A in the historical years are plotted in the top panel of Figure D - 40, and its wind seasonal shapes are plotted the bottom panel Figure D - 40.

[79] Climatology Lab: *https://www.climatologylab.org/maca.html*.

Figure D - 40: Climate Scenario A Wind Speed and Temperature Data for the Gorge



The climate scenario A wind-temperature correlations data are plotted in the top panel in Figure D - 40. They are plotted similarly to the ERA5 wind-temperature correlations data plotted in the top panel in Figure D - 39. The scenario A daily minimum temperatures along the x-axis have been divided into ten equal population percentile subsets. For example, the lowest 10th percentile of the temperature distribution is inside the interval [-10.8 F, 25.8 F). On the other hand, the highest 10th percentile is inside the interval [57.1 F, 76.1 F]. Scenario A's temperature percentiles are a couple of degrees lower than those of ERA5.

It's evident that the climate wind speed distributions in Figure D - 40 are significantly lower than those of ERA5 in Figure D - 39. Furthermore, for scenario A, the wind speed distribution at the lowest 10th percentile of temperature is not significantly lower than the other percentile groups, which does not match the correlations of ERA5.

Therefore, the wind-temperature distributions in the top panel of Figure D - 40 were bias-corrected as described in the next section to resemble those of ERA5 data.

For scenario A monthly wind speed distributions plotted in the bottom panel of Figure D - 40, its seasonal patterns seem to be opposite to those of ERA5 plotted in the bottom panel of Figure D - 39: lower wind speeds for late spring to summer months, and higher wind speeds for late fall to winter months.

Thus, the monthly wind speed distributions for scenario A were also bias-corrected to resemble those of ERA5. However, this monthly bias-correction was performed *after* the wind-temperature correlations bias-correction.

In summary, there were two bias-corrections to the climate scenario wind speed distribution, the first one to resemble the ERA5 wind speed-temperature correlations, and afterward a second one to resemble the ERA5 monthly wind speed distributions.

Bias-Correction of Climate Scenario Wind-Temperature Correlations

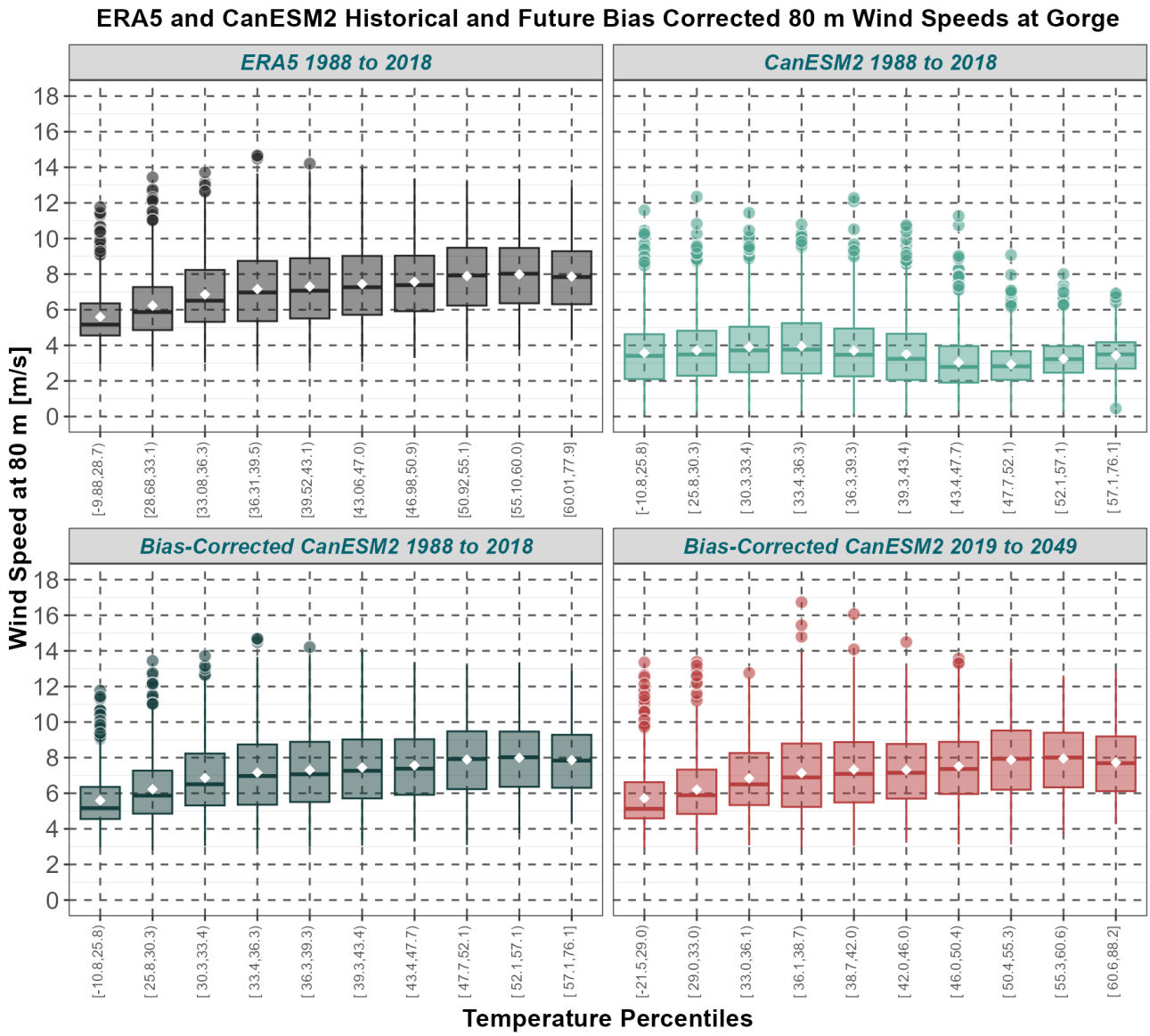
For the historical years 1988 to 2018, the bias-corrections of climate scenario A wind-temperature correlations to resemble the ERA5 wind-temperature correlations are performed for each of the ten temperature percentile groups separately. For example, for the lowest 10th percentile of scenario A temperatures at the left-most boxplot where the daily minimum temperatures are in interval [-10.8 F, 25.8 F) in the top panel of Figure D - 40, the scenario A wind speed distribution is bias-corrected to the corresponding ERA5 wind speed distribution for the lowest 10th percentile of ERA5 temperatures inside the interval [-9.88 F, 28.7 F) in the top panel of Figure D - 39.

The bias-correction method for the distributions is quantile delta mapping[80] (QDM) as recommended by a climate scientist consulting with the Council. The bias-corrected climate scenario A wind-temperature correlations are plotted in the bottom left panel of Figure D - 41.

The ten sets of QDM parameters used to bias-correct the scenario A wind-temperature correlations to resemble the ERA5 wind-temperature correlations for the historical years 1988 to 2018 were saved and then used to bias-correct the scenario A wind-temperature correlations for the climate scenario years 2019 to 2049, plotted in the bottom right panel of Figure D - 41.

[80] See https://medium.com/@juanmi.gutierrez/quantile-mapping-bias-correction-63ed01d5a618 for an introduction.

Figure D - 41: Comparison on Wind Speeds and Temperatures of ERA5 and Climate Scenario A Data (with and without Bias-Correction) at the Gorge



All four plots in Figure D - 41 are wind-temperature correlations. The wind speed distributions are along the y-axis versus ten daily minimum temperature percentile groups along the x-axis. The top-left panel is the ERA data for 1988 to 2018 from the top panel of Figure D - 39; the top-right panel is the (un-bias-corrected) scenario A data for climate scenario years 1998 to 2018 from the top panel of Figure D - 40. The bottom-left panel is the bias-corrected scenario A data for climate scenario years 1998 to 2018. It's evident that the bias-corrected wind-temperature correlations excellently match those of the ERA5 data in the top-left panel.

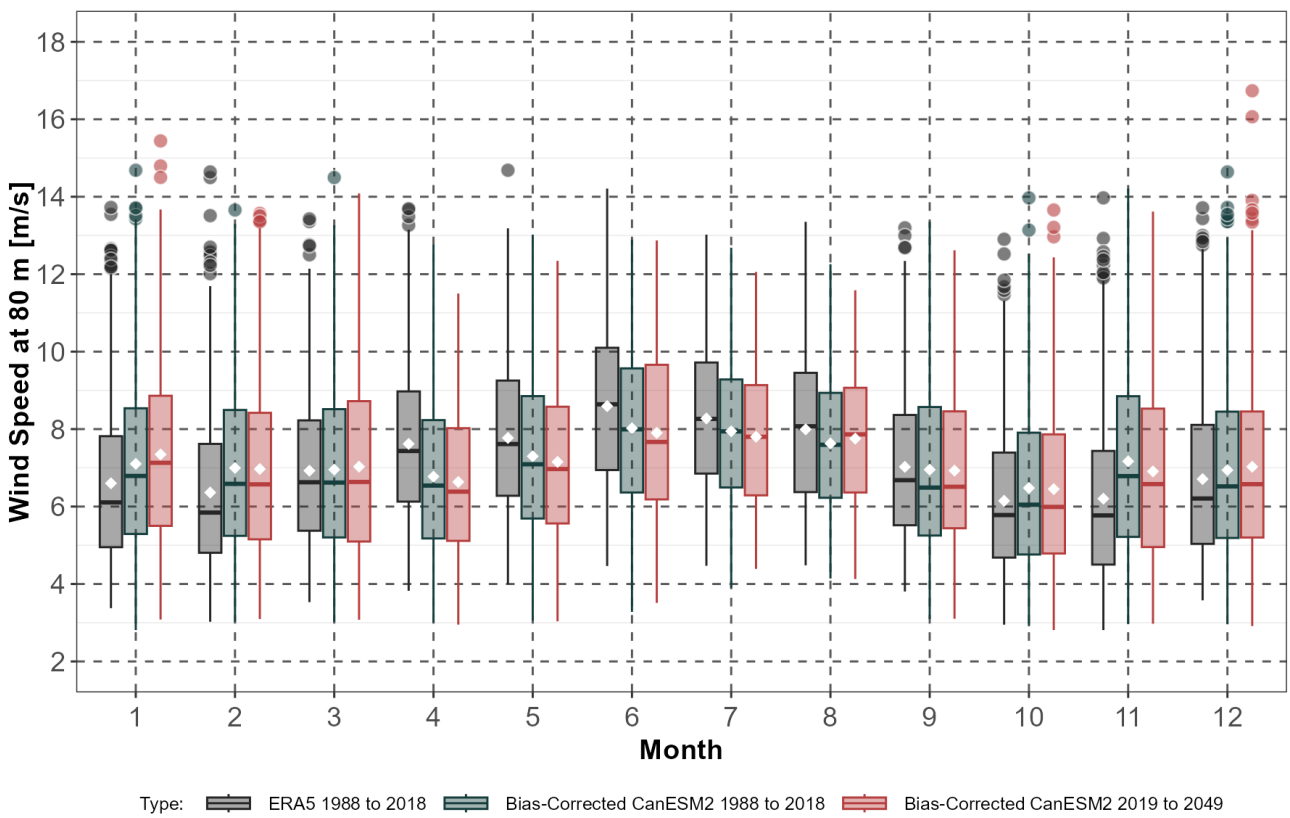
Finally, the bottom right in Figure D - 41 is the bias-corrected scenario A data for climate scenario years 2019 to 2049. Since these bias-corrected wind-temperature correlations use bias-correction parameters developed for scenario A data for climate scenario years 1998 to 2018, they do not match

perfectly to the ERA5 data in the top-left panel, which is expected. The difference could be attributed to effects of climate change. Nevertheless, the ERA5 wind-temperature correlations are well preserved, especially for the lowest 10th percentile of temperatures, where the wind speed distribution is significantly lower than all other percentile groups.

Bias-Correlation of Seasonal Patterns

In Figure D - 42, the monthly ERA5 wind speed distributions in the gray boxplots are plotted with the bias-corrected (for wind-temperature correlations) scenario A for climate scenario years 1988 to 2018 in the green boxplots, and the bias-corrected scenario A for climate scenario years 2019 to 2049 in the red boxplots.

Figure D - 42: Monthly ERA5 and Bias-Corrected Climate Scenario A Wind Speeds at the Gorge



In In Figure D - 42, the bias-corrected scenario A wind speed data for the historical years 1988 to 2018 (in green boxplots) were bias-corrected to resemble the ERA5 wind speed-temperature correlations. However, after that (first) bias-correction they do not resemble the ERA5 monthly wind speeds distributions (in gray boxplots). Therefore, the bias-corrected scenario A data undergo a second bias-correction to resemble the ERA5 monthly distributions.

This monthly bias-correction was performed on each of the 12 monthly distributions separately, using a simpler method. For example, for month 1, in unit of meter/sec, the averages (e.g., the white diamonds in Figure D - 42) of the ERA5, scenario A (1988 – 2018), and scenario A (2019 – 2049) are

6.60, 7.10, and 7.35 respectively. Then the ratio of the ERA5 average to the scenario A (1988 – 2018) average is calculated, which results in the ratio $6.60/7.10 \cong 0.930$.

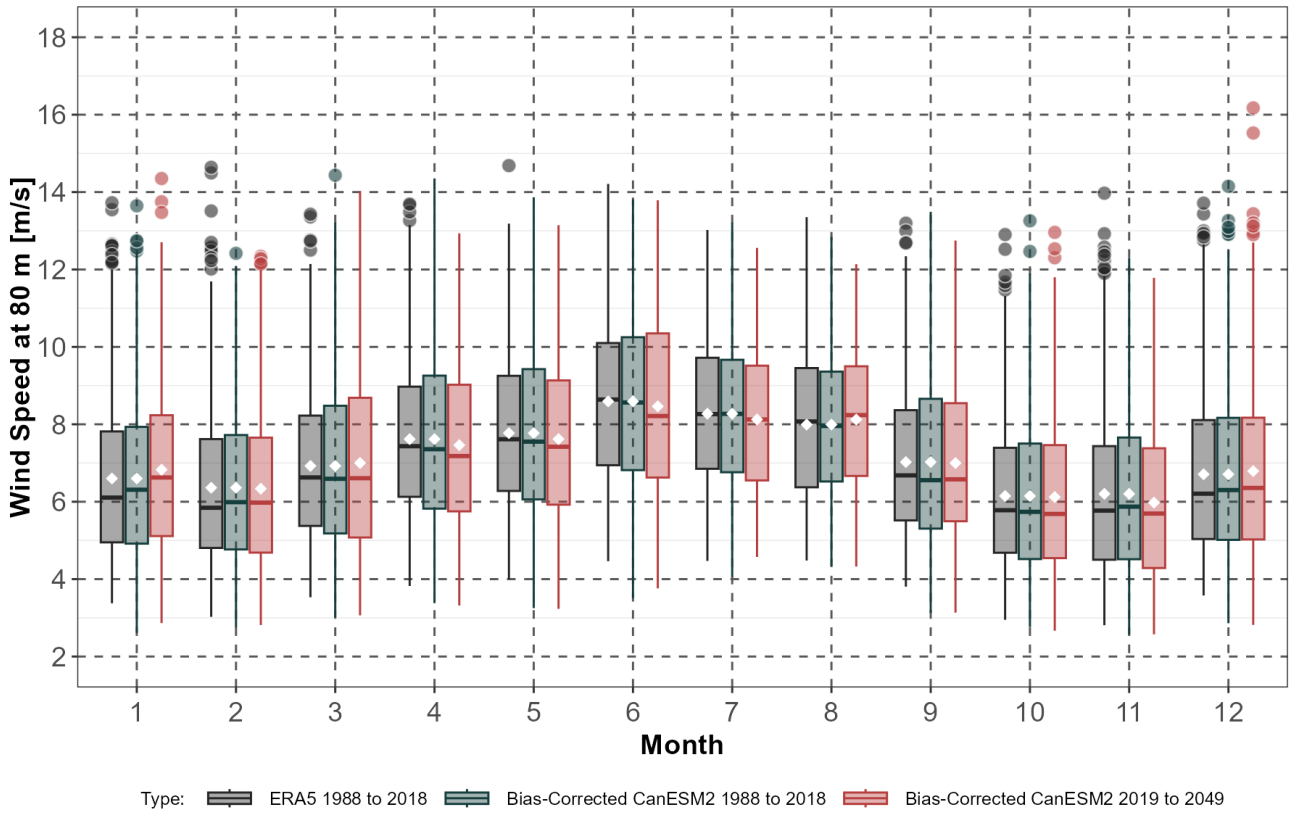
The (second) bias-corrections of both scenario A (1988 – 2018) and scenario A (2019 – 2049) for month 1 consist of multiplying all wind speeds in both distributions by the ratio 0.93. Similarly, bias-corrections of scenario A data for other months are performed using the same method: multiplication by the ratio of averages. Table D - 20 lists the relevant average wind speeds and ratios for all 12 months.

Table D - 20: Monthly Average Wind Speeds in [m/s] and Bias-Correction Ratios

Month	Avg ERA5 Wind Speed	Avg Scen A (1988 – 2018) Wind Speed	Ratio
1	6.60	7.10	0.93
2	6.36	7.00	0.91
3	6.93	6.95	1.00
4	7.62	6.77	1.12
5	7.77	7.30	1.06
6	8.59	8.02	1.07
7	8.27	7.94	1.04
8	7.99	7.63	1.05
9	7.02	6.95	1.01
10	6.15	6.48	0.95
11	6.20	7.17	0.87
12	6.71	6.94	0.97

The final bias-corrected monthly wind speed distributions for scenario A are plotted in Figure D - 43 below.

Figure D - 43: Final Bias-Corrected Climate A Wind Speeds at the Gorge



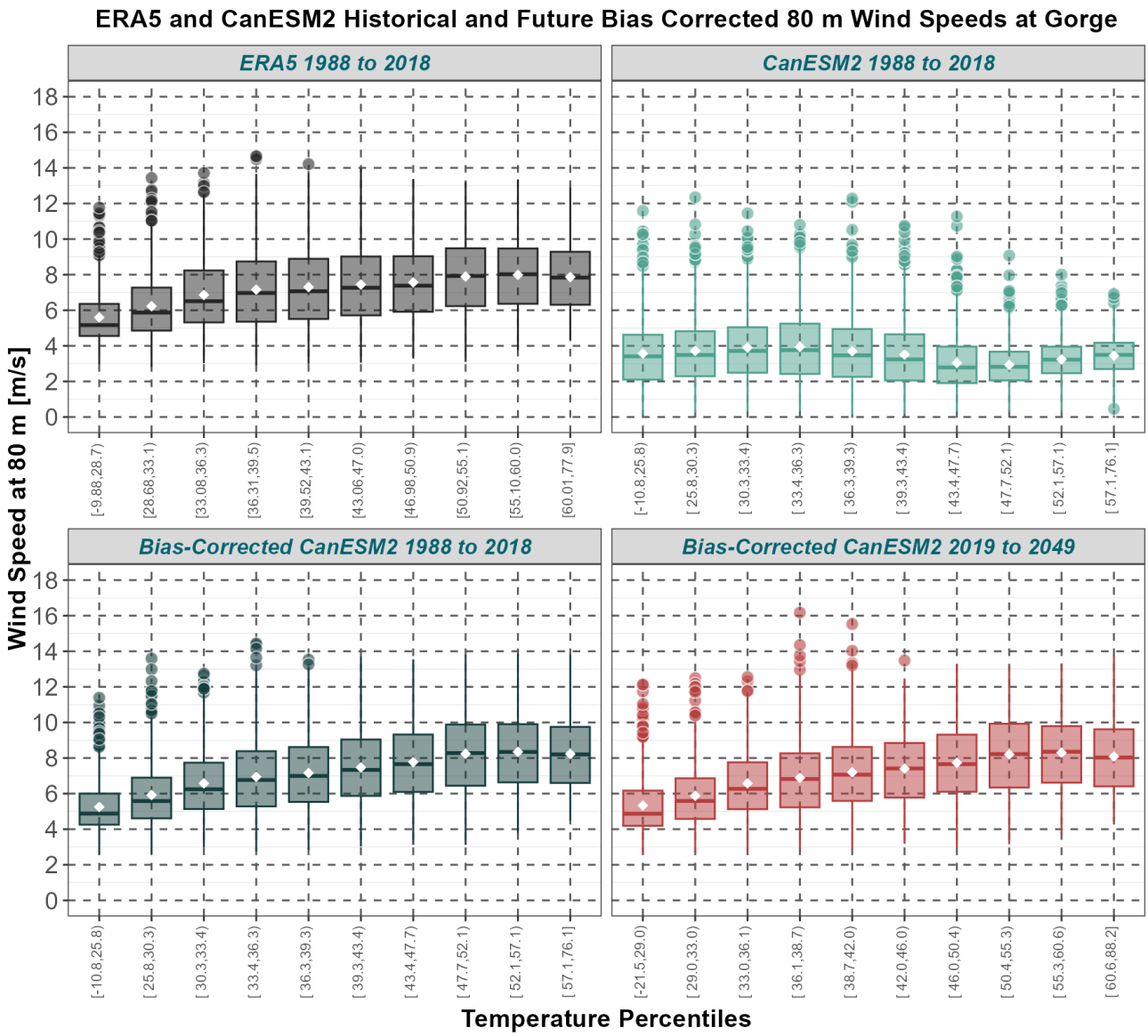
In Figure D - 43, the final bias-corrected scenario A data for the historical years 1988 to 2018 in the green boxplots resemble the ERA5 data in the gray boxplots, with their averages being exactly the same. Furthermore, the seasonal patterns in the scenario A wind speeds match the ones in the ERA5 data: lower speeds for the late fall and winter months, and higher speeds for the late spring and summer months.

Moreover, the final bias-corrected scenario A data for climate scenario years 2019 to 2049 in the red boxplots have larger differences relative to the ERA5 data in the gray boxplots. The differences could be attributed to climate change. Nevertheless, the scenario A data still retain the ERA5 seasonal patterns, and have monthly averages close to those of ERA5.

It should be noted that the additional monthly bias-corrections would degrade the excellent matching of the wind-temperature correlations of the bias-corrected scenario A data to those of ERA5, as presented in the bottom panels in Figure D - 41.

Therefore, after first undergoing wind-temperature correlation bias-correction and then monthly wind speed bias-correction, the final wind-temperature plots are presented in the bottom panels of Figure D - 44.

Figure D - 44: Wind Speed and Temperature Correlations for Final Bias-Corrected Climate A Data at the Gorge



In Figure D - 44, both the scenario A (1988 to 2018) data, in the bottom-left panel, and scenario A (2019 to 2049) data in the bottom-right panel, have been bias-corrected twice: first for wind-temperature correlations, and then second for monthly wind speeds. Since the scenario A data plotted in the bottom panels of Figure D - 41 have undergone just the wind-temperature correlation bias-correction, those distributions are slightly different (and somewhat difficult to notice) than the corresponding ones in the bottom panels of Figure D - 44.

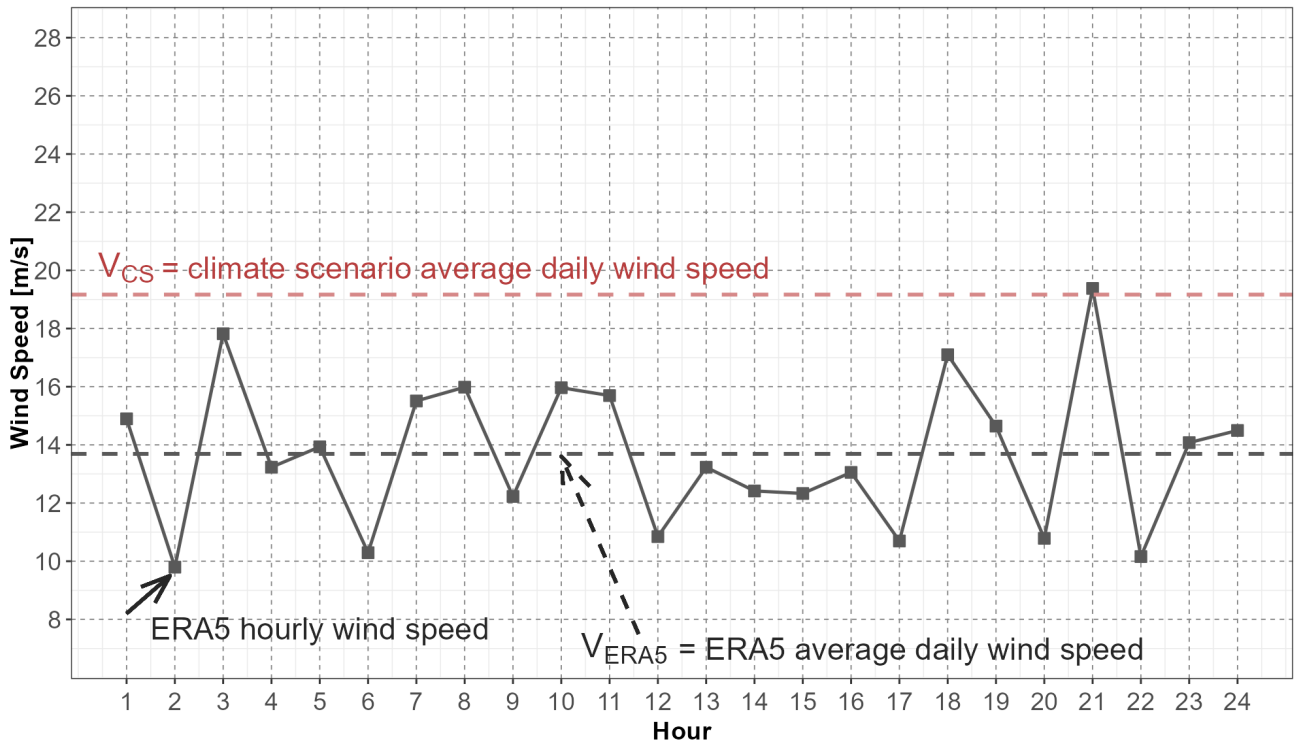
Calculating Hourly Shapes for the Bias-Corrected Daily CL Wind Data

The bias-corrected CL wind data for climate scenario years 2019 to 2049 developed in the previous section are daily averaged wind speeds. The next step is to derive hourly shapes for the daily data

which then become inputs into the TSL model that calculates and outputs hourly wind generation. The hourly wind generation in turn becomes an input in the Council's models.

Given a climate calendar date and its daily averaged wind speed, its hourly shapes are derived from pairing the climate calendar date with a selected ERA5 historical calendar date that has hourly wind speeds. The hourly shape derivations are illustrated in the following two figures.

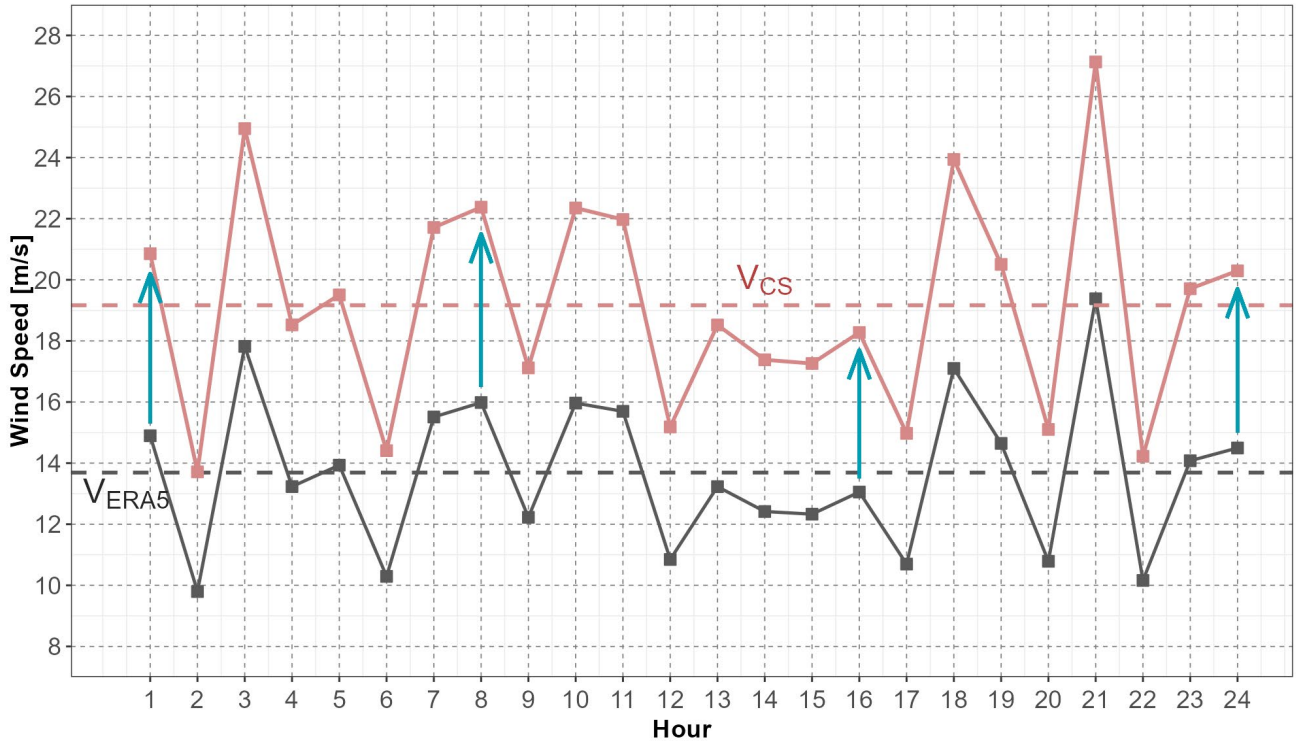
Figure D - 45: Example Wind Speeds for a Day



In Figure D - 45, the example climate scenario daily averaged wind speed V_{CS} is plotted as a light red horizontal dashed line. The example ERA5 24 hourly wind speeds are plotted as gray squares connected by a solid gray curve, and their daily averaged wind speed V_{ERA5} is plotted as a gray horizontal dashed line.

The ratio of the climate scenario daily averaged wind speed to the ERA5 daily averaged wind speed is defined as ratio $= V_{CS}/V_{ERA5}$. Therefore, the climate scenario 24 hourly wind speeds are calculated by multiplying this ratio to the 24 hourly ERA5 wind speeds (in the gray squares). This is illustrated in Figure D - 46 below.

Figure D - 46: Calculating Climate Scenario A Hourly Wind Speeds for an Example Day



In Figure D - 46, the climate scenario 24 hourly wind speeds in the red squares are derived by multiplying the ERA5 24 hourly wind speeds in the gray squares by the ratio of the average wind speeds, V_{CS}/V_{ERA5}.

Therefore, to enable calculations of climate scenario hourly wind speeds as illustrated here, a method was developed to select an ERA5 historical date (with its corresponding 24 hourly wind speeds) to pair with a given climate scenario calendar date. Given that the climate scenario wind data used in the Ninth Plan cover climate scenario years 2019 to 2049, and the recent ERA5 historical data cover years 1988 to 2018, a few methods were considered.

Ultimately, a method suggested by a climate scientist consulting with the Council is adopted based on assuming the hourly wind shapes could be correlated to properties of the daily averaged wind speeds. The first assumption is that since the daily average wind speeds are correlated with temperature percentiles as presented in Figure D - 44, then perhaps the hourly wind shapes could also be correlated to the temperature percentiles. In Figure D - 47 below the ERA5 and scenario A (2019 to 2049) wind-temperature correlation plots are copied from Figure D - 44.

Figure D - 47: ERA5 and Final Climate Scenario A Wind Speeds at the Gorge

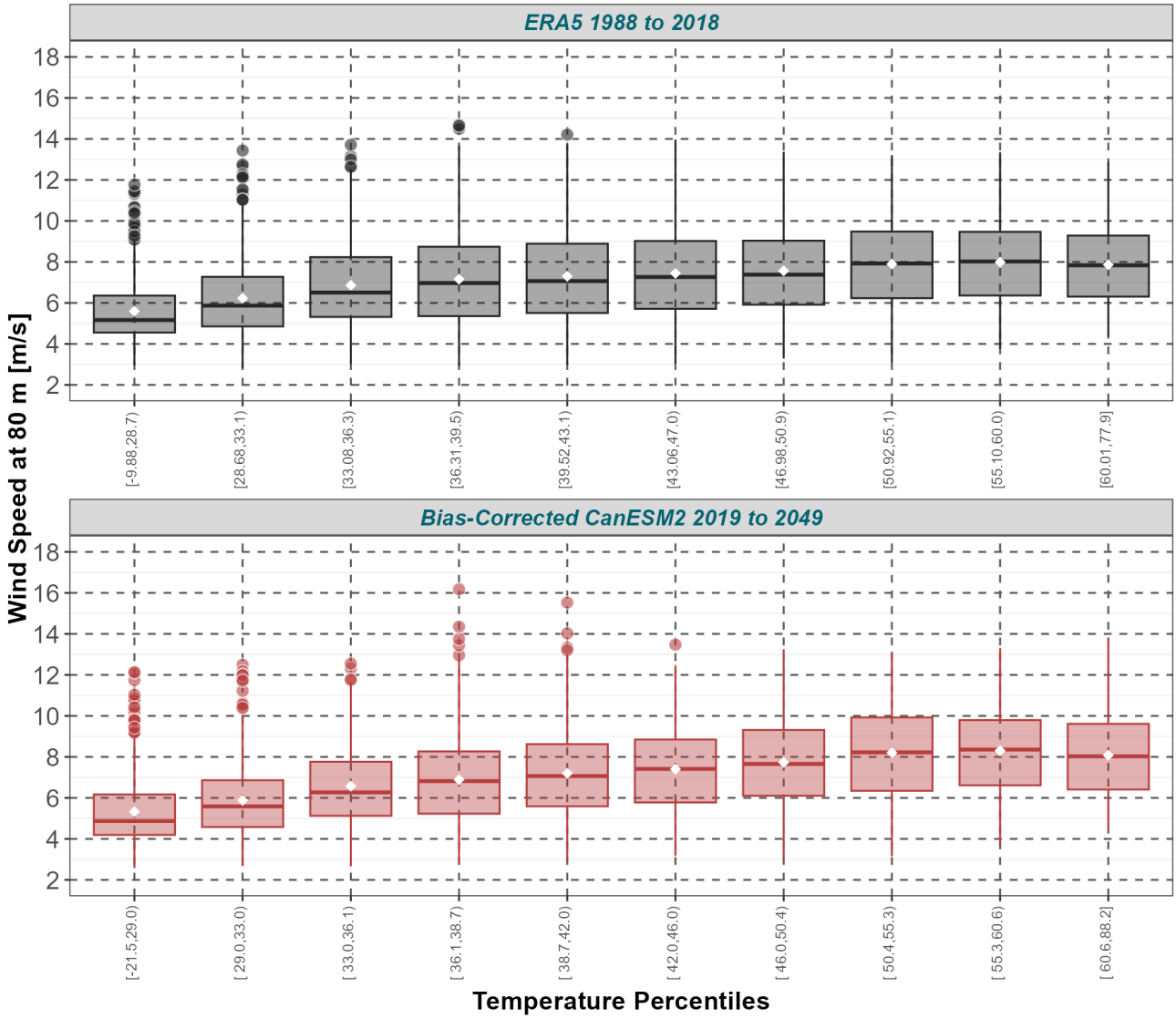


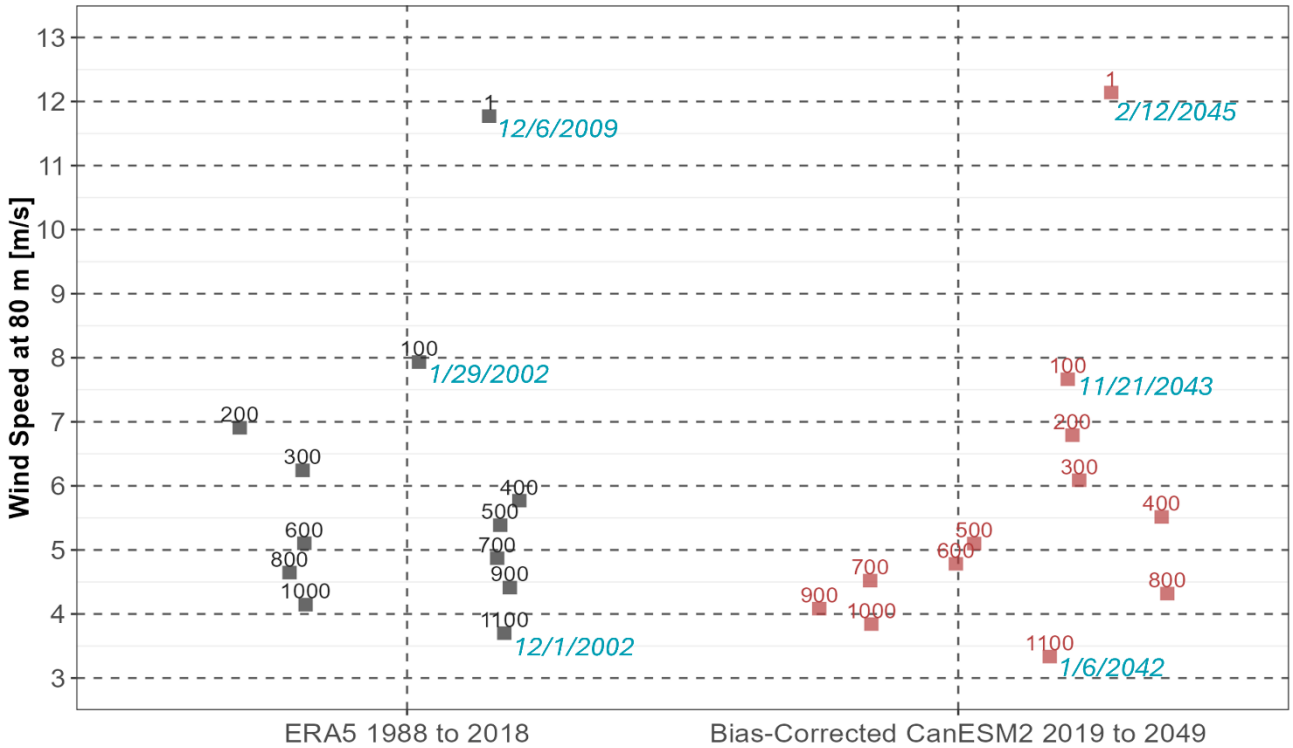
Figure D - 47 shows that daily average wind speeds are lower for the very low temperature percentiles on the left side of the plots. Then perhaps hourly wind shapes for those low temperature percentiles could be different than those for the higher temperature percentiles. Therefore, pairing a climate scenario date with a selected ERA5 historical date is done for each of the ten temperature percentile groups separately.

For example, climate scenario dates in the left-most red boxplot where the climate scenario temperatures are in the interval [-21.5 F, 29.0F) are paired only with the ERA5 historical dates in the left-most gray boxplot where the ERA5 temperatures are in the interval [-9.88 F, 28.7 F). Within the left-most red boxplot and gray boxplot, the distributions of daily averaged wind speeds range from a maximum of around 12 m/s to a minimum of around 2 m/s.

The second assumption is that perhaps the higher and lower wind speeds of the distributions could have different hourly shapes. Therefore, for these two left-most boxplots, pairing a climate scenario

date with a selected ERA5 historical date is done by the rank of the wind speeds. More specifically, the climate scenario date with the highest wind speed is paired with the ERA5 historical date with the highest wind speed. Next, the climate scenario date with the second highest wind speed is paired with the ERA5 historical date with the second highest wind speed, and so on. Figure D - 48 below illustrates the date-pairing process.

Figure D - 48: Wind Speed Pairing Process for Developing Hourly Shapes



For the 31 years of ERA5 (1988 to 2018) data and scenario A (2019 to 2049) data, there are 11,323 daily average wind speed data. Therefore, the lowest 10th percentile of the daily minimum temperatures has 1,133 daily data, which are still too many to be plotted in a figure.

Thus, in Figure D - 48, only 12 sample ranks (out of a total of 1,133 ranks) of wind speeds are plotted for the ERA5 and scenario A (2019 to 2049) data. The sample ranks are (1, 100, 200, ..., 1100) where rank-1 represents the highest wind speed, and rank-1100 represents wind speed near the minimum. The rank number is plotted on top of the corresponding square. For example, the rank-1, rank-100, and rank-1100 ERA5 wind speeds in units of m/s are 11.8, 7.9, and 3.7 respectively, and plotted in the gray squares on the left side. The rank-1, rank-100, and rank-1100 scenario A (2019 to 2049) wind speeds are 12.1, 7.7 and 3.3 respectively, and plotted in the red squares on the right side.

Furthermore, for the ERA5 data on the left side, the historical dates corresponding to rank-1, rank-100, and rank-1100 wind speeds are 12/6/2009, 1/29/2002, and 12/1/2002 respectively. For the scenario A (2019 to 2049) data, the climate scenario dates corresponding to rank-1, rank-100, and rank-1100 wind speeds are 2/12/2045, 11/21/2043, and 1/6/2042, respectively. Of course, historical

and climate scenario dates exist for other wind speeds in Figure D - 48, but only these few dates are plotted to avoid over-crowding.

Thus, for the rank-1 speeds, climate scenario date 2/12/2045 is paired with ERA5 historical date 12/6/2009; for the rank-100 speeds, climate scenario date 11/21/2043 is paired with ERA5 historical date 1/29/2002; and for the rank-1100 speeds, climate scenario date 1/6/2042 is paired with ERA5 historical date 12/1/2002. Date pairings between climate scenario dates and ERA5 dates are also performed for the remaining wind speeds in Figure D - 48, and furthermore, for all remaining 1,127 ranks of wind speeds in the left-most boxplots of Figure D - 47 that are not explicitly plotted in the Figure D - 48.

The same pairing process is also applied to the remaining 9 temperature percentile boxplots in Figure D - 47, and thus completing the pairings of all scenario A climate scenario dates with specific ERA5 historical dates. Moreover, by pairing a scenario A climate scenario date with a selected ERA5 historical date, it enables the 24 hourly ERA5 wind speeds (on that ERA5 date) to be used to calculate the 24 hourly scenario A wind speeds on that paired climate scenario date, as discussed previously.

At the end of this process, hourly winds for all scenario A (2019 to 2049) data are calculated.

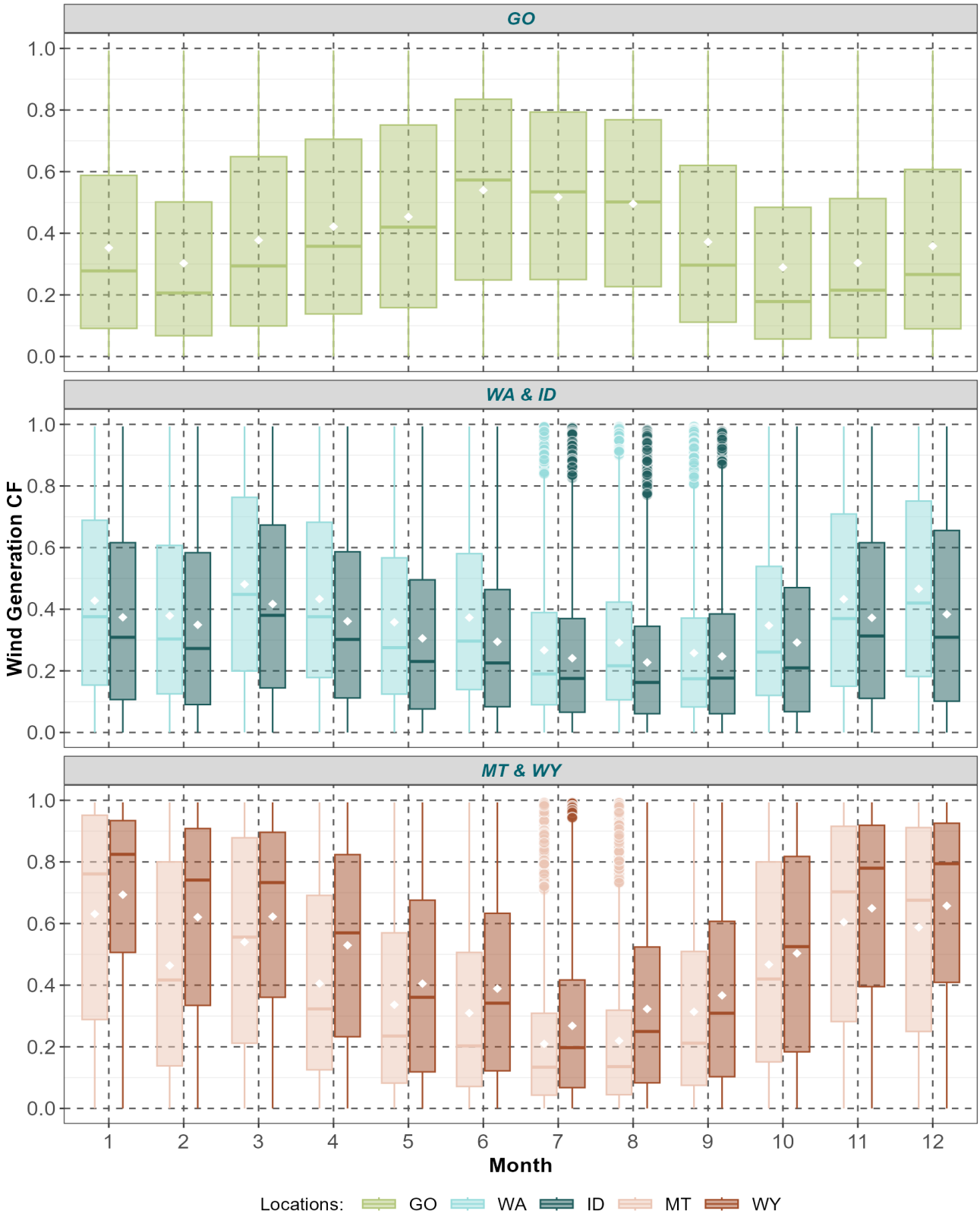
This methodology for estimating climate scenario hourly wind speed was presented to CWAC. While some members suggested a few analyses to evaluate how well the GCMs simulate climate scenario wind speed data, they did not have any objection to the methodology.

Climate Scenario Hourly Wind Generation

Although examples in the previous sections are for the combination of only the 80-m hub-height, the Gorge location and climate scenario A, the same bias-correction and hourly wind speed calculation processes have also been applied to all remaining combinations of two hub-heights, five in-region locations, and three climate scenarios.

Therefore, the CL climate scenario hourly wind speed data for 2019 to 2049 at turbine hub-heights of interest are available as inputs into the TSL model to calculate wind generation for a set of specified turbine parameters. The monthly aggregate (A, C, G) climate scenario hourly wind generation CFs for the five in-region locations, the Gorge (GO), southeast Washington (WA), Idaho (ID), Montana (MT) and Wyoming (WY) are plotted in Figure D - 49 for the reference 100-m wind turbine, Vestas v112-30.

Figure D - 49: Final Monthly Aggregate Wind Speeds for 100 M Wind Turbine



In Figure D - 49, the aggregate (A, C, G) climate scenario wind generation CFs for the 100-m hub height Vestas v112-30 turbine are plotted along the y-axis as boxplots with the months along the x-axis. CFs for the five in-region wind fleet locations, the Gorge (GO), southeast Washington (WA), Idaho (ID), Montana (MT) and Wyoming (WY), have different seasonal patterns and thus are plotted in different panels.

In the top panel, the Gorge (GO) CFs are plotted in the light green boxplots and they reflect the same seasonal patterns of scenario A (2019 to 2049) in the red boxplots of Figure D - 43: lower for the late fall and winter months, and higher for the late spring and summer months.

In the middle panel, the southeast Washington (WA) and Idaho (ID) CFs are plotted in the light teal and green boxplots respectively. Their seasonal patterns are lower for months of July, August, and September, and higher for other months.

Finally, in the bottom panel, the Montana (MT) and Wyoming (WY) CFs are plotted in the light red and darker red boxplots respectively, and the seasonal patterns seem to be opposite to those of the Gorge (plotted in the top panel): higher for the late fall and winter months, and lower for the late spring and summer months. In general, the complementary seasonal patterns of the Gorge, and the Montana and Wyoming group are beneficial for the power system since it is less likely to have low seasonal wind generation region wide.

Table D - 21 below lists the averages (i.e., the white diamonds inside the boxplots) of the wind CFs for the 100-m hub height Vestas v112-30 turbine for the five wind fleet locations.

Table D - 21: Monthly Average Aggregate Climate Scenario (A, C, G) Wind CFs

Month	1	2	3	4	5	6	7	8	9	10	11	12
GO	0.35	0.30	0.38	0.42	0.45	0.54	0.52	0.50	0.37	0.29	0.30	0.36
WA	0.43	0.38	0.48	0.43	0.36	0.37	0.27	0.29	0.26	0.35	0.43	0.47
ID	0.37	0.35	0.42	0.36	0.31	0.29	0.24	0.23	0.25	0.29	0.37	0.38
MT	0.63	0.46	0.54	0.41	0.34	0.31	0.21	0.22	0.31	0.47	0.60	0.59
WY	0.69	0.62	0.62	0.53	0.41	0.39	0.27	0.32	0.37	0.50	0.65	0.66

In Table D - 21, the maximum monthly average wind CF is 0.69 for the WY wind fleet for January. The minimum monthly average wind CF is 0.21 for the MT wind fleet for July.

The annual average wind CFs for the five wind fleet locations are listed in Table D - 22 below.

Table D - 22: Annual Average Aggregate Climate Scenario (A, C, G) Wind Capacity Factors

Wind Fleet Locations	Annual Average
GO	0.399
WA	0.376
ID	0.322
MT	0.424
WY	0.502

The highest and lowest overall wind CFs are the WY wind fleet at 0.502 and the ID wind fleet at 0.322, respectively.

The wind CFs for all three climate scenarios, A, C, and G were plotted in aggregate in Figure D - 49. Nevertheless, the CFs for each separate climate scenario look very similar to these aggregates. The reason is that, at each of the five wind fleet locations for each of the three climate scenarios, the various bias-corrections discussed previously are applied to the climate wind speed data in the historical time-period, the years 1988 to 2018, to resemble the ERA5 historical wind data. Therefore, all three bias-corrected climate scenario wind data for years 1988 to 2018 resemble very closely the same ERA5 historical wind data. Furthermore, the same bias-correction parameters developed for the historical time-period are also applied to climate scenario wind data for years 2019 to 2049. Thus, the three bias-corrected climate scenario wind speed data for years 2019 to 2049 also somewhat resemble the same ERA5 historical wind data, just not to the same degree as the climate data in the historical period, from 1988 to 2018. As an example, see Figure D - 43 and Figure D - 44 for data at the Gorge location for climate scenario A.

Very Low Wind Generation

It is prudent to analyze the frequency and duration of very low wind generation since power system planners would have to develop a program to acquire sufficient and economical generation from other sources to meet load. Even though there is no standard definition of very low wind generation, this analysis assumes wind generation is low when the daily average capacity factor (CF) is less than or equal to the 10th percentile of the distribution of all daily average CFs.

For simplicity, let the 10th percentile of all daily average CFs be represented by CF_{10}, and let those days where their CFs $\leq CF_{10}$ be referred to as low-CF days. For the five wind fleet locations, their CF_{10}'s are listed in Table D - 23 below.

Table D - 23: The 10th Percentiles of the Distributions of Daily Average Wind CFs Calculated from The Hourly CFs for the GO, WA, ID, MT, and WY Wind Fleet locations

10th Percentiles of CFs	GO	WA	ID	MT	WY
$\boldsymbol{CF_{10}}$	0.085	0.111	0.069	0.089	0.129

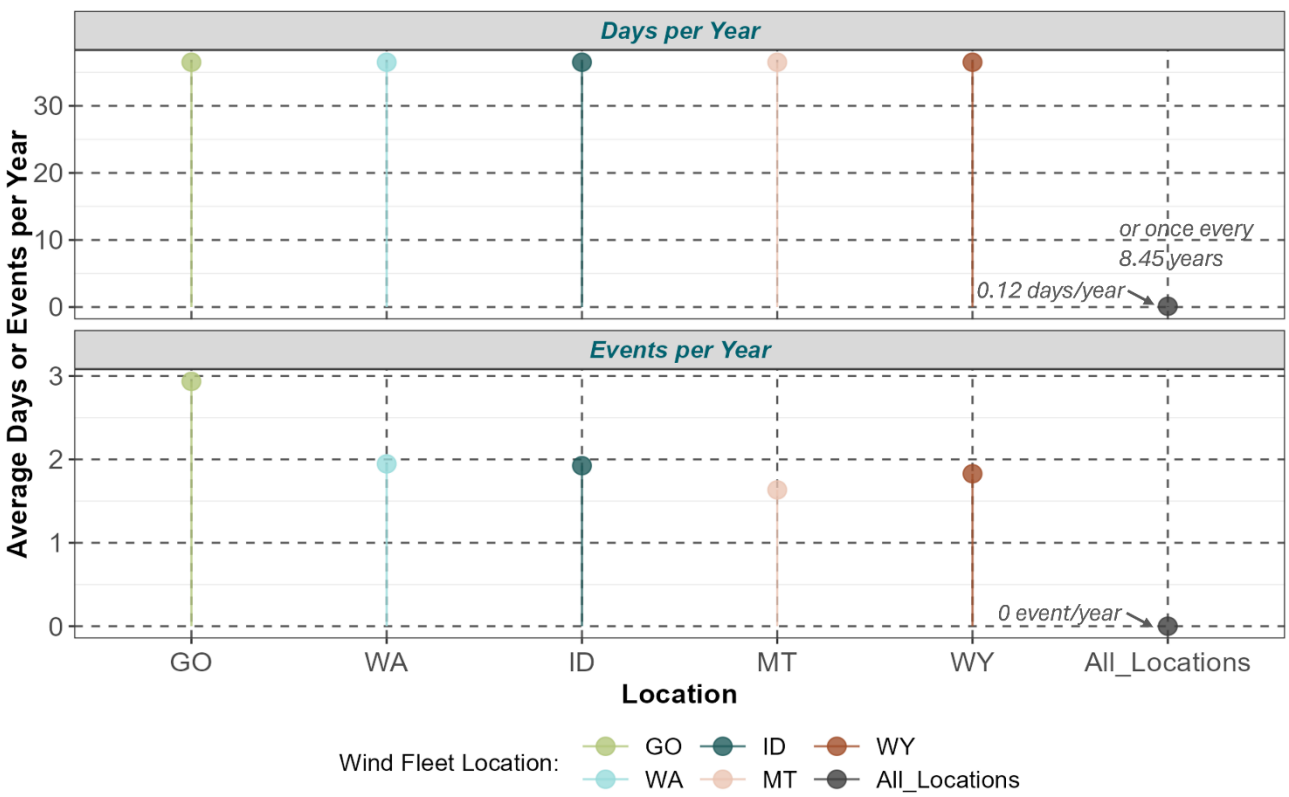
For the aggregate 93 climate scenario years, resulting from the three climate scenarios each having 31 climate scenario years, there are a total of 33,945 days of daily average CFs. Therefore, the number of days where their daily average CFs $\leq CF_{10}$ is about 3,395, depending on the number of ties. Furthermore, for each of the five wind fleet locations, there are about the same number of low-CF days, 3,395. However, there are only 11 low-CF dates common to all five wind fleets, where on those common dates, the daily average CFs of all five wind fleets are less than or equal to their respective CF_{10}'s listed in Table D - 23. Therefore, the probability for a day where the entire in-region daily average wind generation is very low is $11/33{,}945 \cong 0.00032$, which is quite small.

However, instead of analyzing the total number of low-CF days or dates for all 93 climate scenario years, a more interpretable quantity could be the average number of low-CF days per year. For example, for all five wind fleet locations, the average number of low-CF days is $(3{,}395 \text{ days})/(93 \text{ years}) \cong 36.5$ days per year (where the daily average CF $\leq CF_{10}$). Furthermore, the average number of low-CF days common to all five wind fleets farm is $(11 \text{ days})/(93 \text{ years}) \cong 0.12$ days per year.

Since 0.12 days per year is less than 1 day per year, then the reciprocal is, $1/(0.12 \text{ days per year}) \cong 8.45$ years per low-CF day. In other words, for all five wind fleets simultaneously having one common low-CF day, the frequency is on average once every 8.45 years.

In the top panel of Figure D - 50 below, the average number of low-CF days per year for the five wind fleet locations are plotted.

Figure D - 50: Low Wind Events in Climate Scenario Wind Profiles



There are on average 36.5 low-CF days per year for each of the five wind fleet locations: GO (light green circle), WA (blue circle), ID (dark green circle), MT (light red circle) and WY (dark red circle), listed from left to right on the x-axis. Furthermore, on average only around 0.12 common low-CF days per year for all five wind fleet locations, plotted in the gray circle on the right side.

Among these low-CF days could be subsets of three-or-more consecutive low-CF days, which are conditions under which it is even more challenging to operate the power system to meet load. Let each set of three-or-more consecutive low-CF days be referred to as a low-CF event. For example, for the GO wind fleet, among the 3,395 total low-CF days, there are 273 low-CF events.

In terms of average number of low-CF events per year, for the GO wind fleet, it is $(273 \text{ events})/(93 \text{ years}) \cong 2.94$ average number of events per year. In the bottom panel of Figure D - 50 above, the average number of low-CF events per year for the five wind fleet locations and for All-Locations are plotted. Going from left to right on the x-axis, the values are: GO (light green circle) 2.94; WA (blue circle) 1.95; ID (dark green circle) 1.92; MT (light red circle) 1.63; WY (dark red circle) 1.83; All-Locations (gray circle) 0. Therefore, the entire (in-region) wind fleet does not have very low generation that lasts for 3 or more days.

Climate Scenario Solar Generation Profiles

Climate scenario solar radiation data, like the climate scenario wind speed data, are not included in the RMJOC data sets, but climate solar data from compatible scenarios are also available from the Climatology Lab (CL) at the University of California, Merced.[81]

However, during the Climate and Weather Advisory Committee meeting,[82] climate scientists suggested that the GCMs, due to the coarse grid size, could not model very well cloud cover over a fine spatial-scale area such as those occupied by solar farms. Because of this limitation, the climate scenario solar radiation data, specifically the Surface Downwelling Shortwave Radiation equivalent to the global horizontal irradiance (GHI), should not be used to calculate solar generation. Instead, some climate scientists suggested using historical solar radiation data to calculate solar generation.

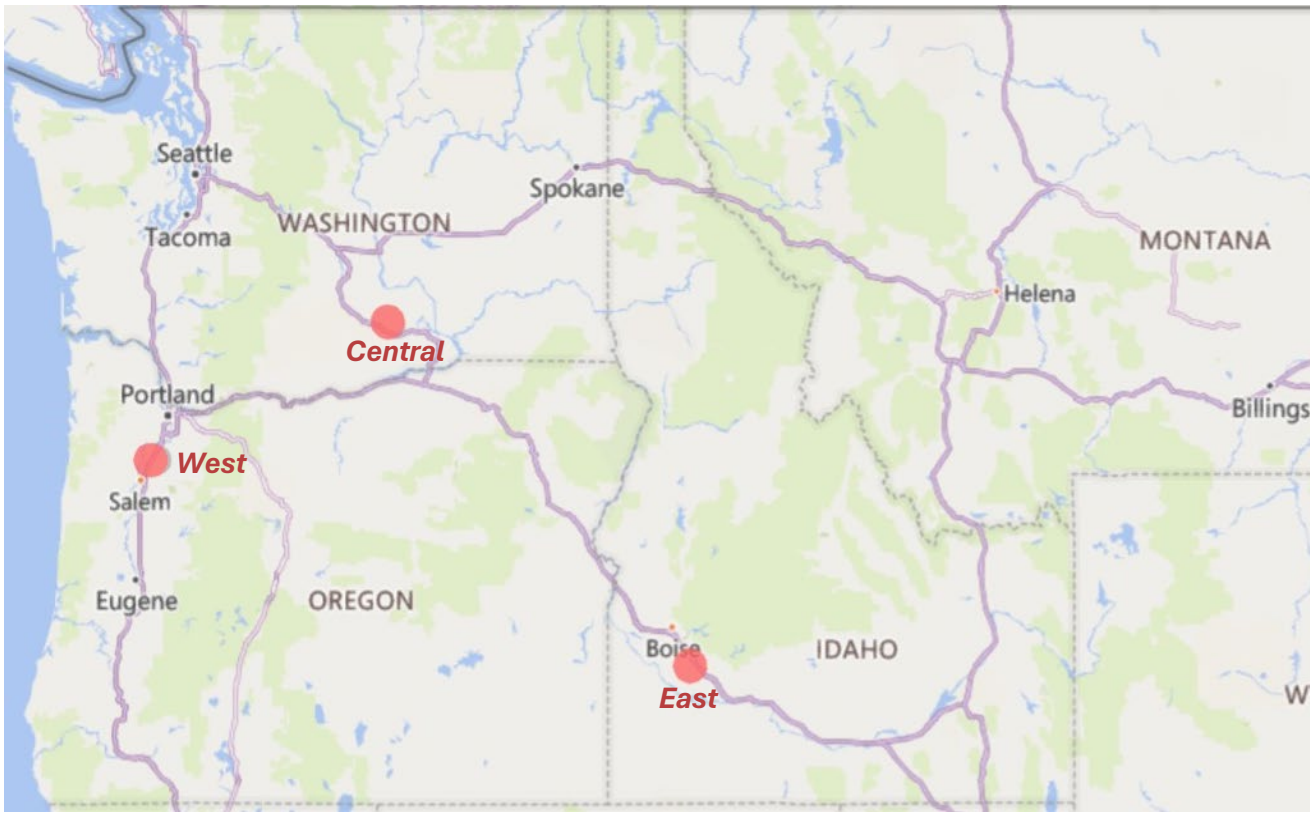
The historical solar data readily available is the 44 years of ERA5 climate data, from 1980 to 2023, embedded in the Time Series Lab (TSL) model. For the solar farm locations selected for the Ninth Power Plan, the synthetic historical solar GHI data are downloaded from the National Solar Radiation Database (NSRDB).[83] Then for selected reference solar panels, their solar CF profiles are calculated by NLR's SAM and used by TSL to bias-correct the ERA5 solar CFs and solar GHI data.

[81] Climatology Lab: *https://www.climatologylab.org/maca.html*.
[82] Discussions during the Climate and Weather Advisory Committee Meeting on 12/04/2024: https://www.nwcouncil.org/meeting/climate-and-weather-advisory-committee-2024-12-04.
[83] See https://nsrdb.nrel.gov/data-viewer.

In-Region Solar Generation Profiles

For the Ninth Power Plan, the Council developed in-region solar generation profiles based on three locations[84] plotted in Figure D - 51 below.

Figure D - 51: Solar Locations for Developing Generation Profiles Assumed in Ninth Power Plan



For simplicity, the three simulated solar farms are referred to as the "West", which is located near Portland; the "Central", which is in south central Washington; and the "East", which is located near Boise. More specifically, the latitude and longitude coordinates of the three locations are listed in Table D - 24.

Table D - 24: The Three In-Region Solar Farm Locations Simulated in the Power Plan

Locations	Latitude	Longitude
West	45.128	-122.828
Central	46.324	-119.822
East	43.304	-115.989

[84] See Technical Appendix G - New Generating Resources in the Ninth Power Plan for more details.

There are two types of solar panels used in the Power Plan modeling: the fixed-axis and 1-axis, both with the same "DC to AC" ratio of 1.4.[85] Furthermore, at each of the three locations, both types of solar panels have the same tilt parameter which is the latitude.

Methodology for Developing In-Region Solar Generation Profiles

As discussed in a previous section, the daily climate scenario streamflow, temperature, and wind data are coincident, since they are outputs from the same climate models, and thus represent the same weather system taking place in the region on the same climate scenario dates. However, the ERA5 historical solar GHI data, which is collected from historical observed data or estimated using climate models, does not represent the same weather systems as the three types of climate scenario data, since it is not an output of global climate models (GCMs).

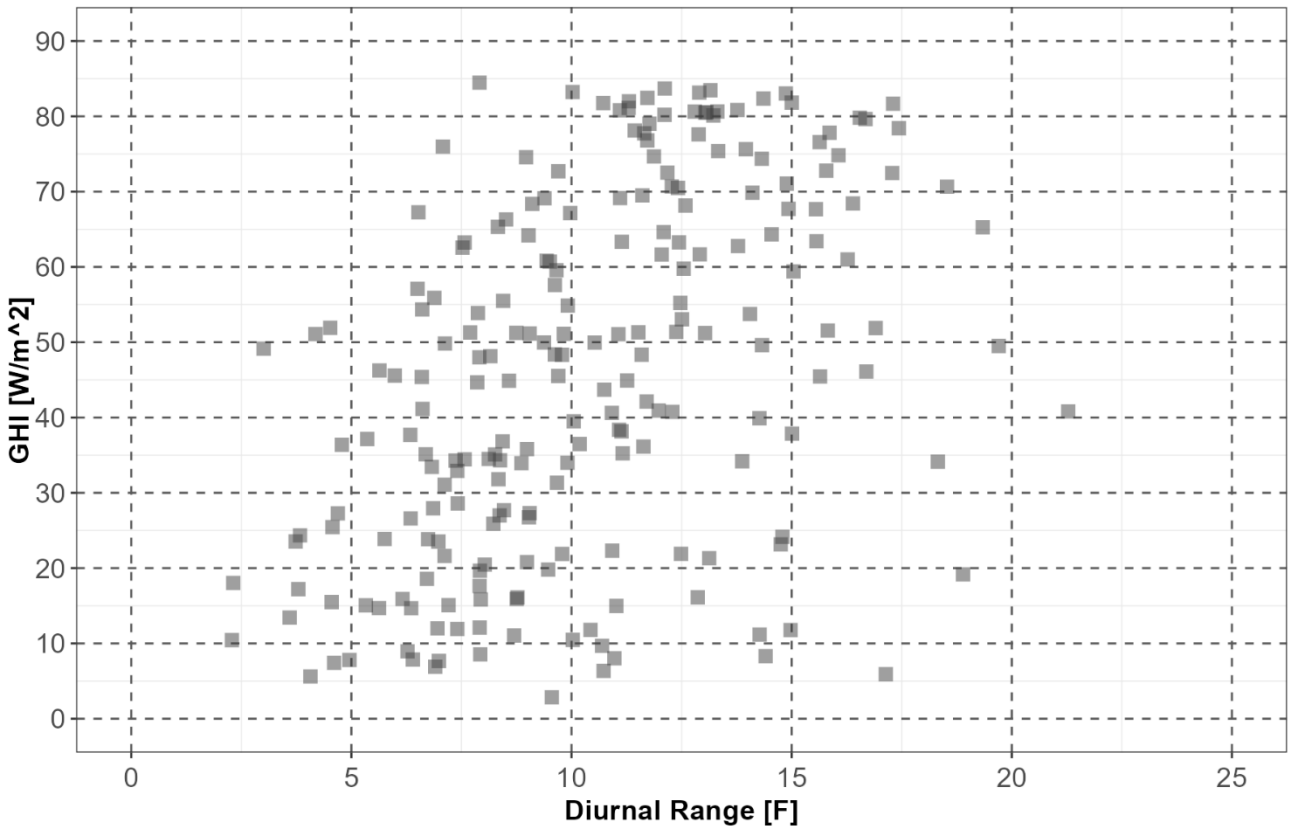
Nevertheless, some climate scientists think that solar data and a type of temperature data (to be discussed) are correlated. The correlations are first analyzed using the ERA5 historical data. It is then assumed that the same ERA5 correlations also exist between the climate scenario solar data and temperature data. Finally, a method is developed to apply the ERA5 correlations to the climate scenario temperature data to estimate synthetic climate scenario solar data.

On the same calendar date of a year (i.e., January 1st, April 18th, etc.), it is believed that the ERA5 GHI data should be correlated to diurnal temperature range, which is defined as the difference between the daily maximum temperature and the daily minimum temperature. A couple of examples are presented below.

As a first example, in Figure D - 52 , at the "West" solar farm, the ERA5 daily average GHI are plotted against the daily diurnal temperature range for the set of 44 January 1st's, a winter day, from 1980 to 2023. However, for correlation analysis, more data should be included. Therefore, to increase size of the data, the five days surrounding January 1st are plotted: December 30th and 31st, January 1st, 2nd, and 3rd, from 1980 to 2023, resulting in $5 \times 44 = 220$ data points. Since these five days are consecutive, they have almost the same daylight hours, and thus almost the same amount of "blue sky" solar irradiance (defined as the solar energy radiation reaching the Earth's surface on a clear, cloudless day). Therefore, differences in GHI among the five consecutive days should be due to different cloud cover, and not due to the small differences in daylight hours or solar elevation angles of the five days.

[85] See Technical Appendix G - New Generating Resources in the Ninth Power Plan for more details.

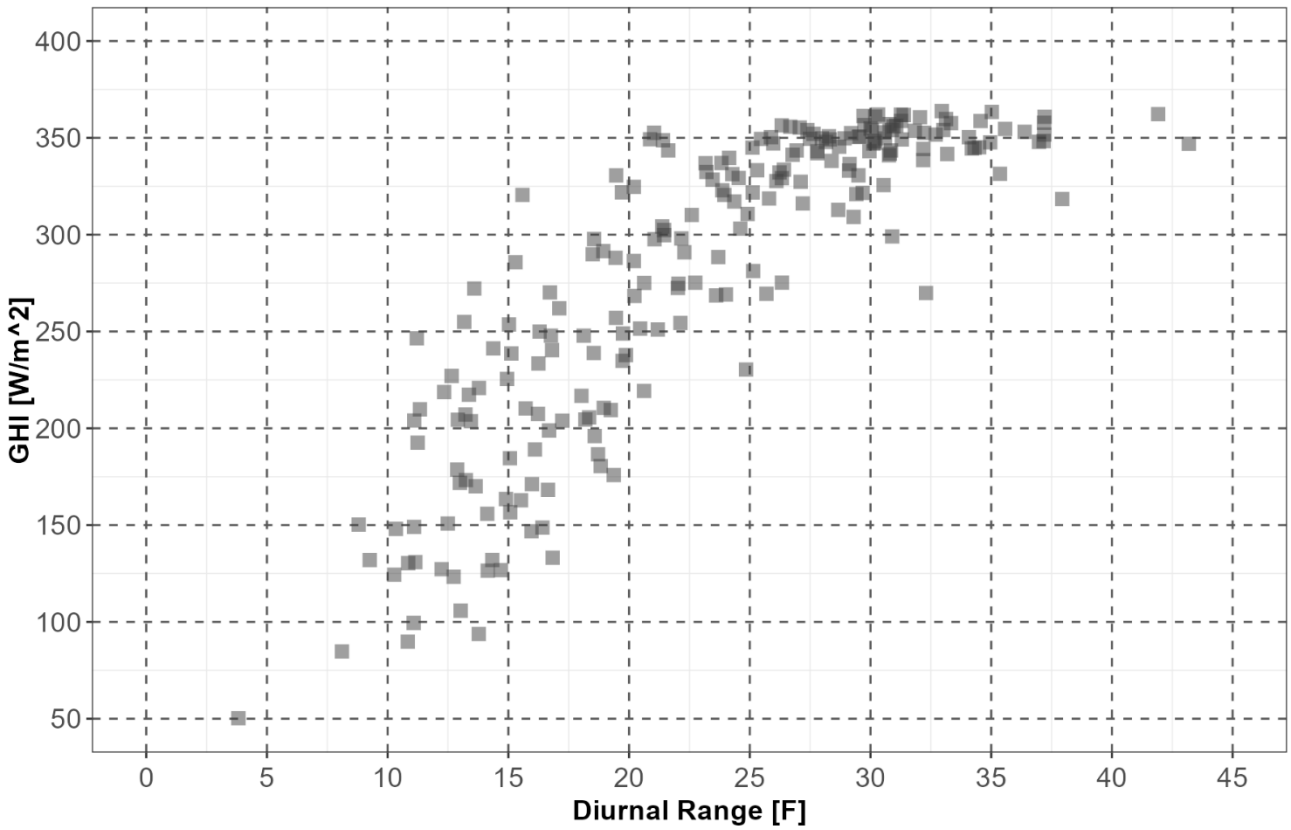
Figure D - 52: ERA5 Daily Average GHI vs Diurnal Temperature on December 30-January 3 for the West Solar Location



In Figure D - 52 above, there seems to be some correlation in the scatter-plot between the ERA5 daily average GHI (plotted along the y-axis) and diurnal temperature range (plotted along the x-axis). However, for a given diurnal temperature range, there is significant variance in the GHI. Nevertheless, it seems that as the diurnal temperature range increases the solar GHI tends to increase as well. The correlation coefficient is small, about 0.46.

Next, also at the "West" solar farm, the correlation between the 44 years of ERA5 daily average GHI and diurnal temperature range is analyzed for a summer day, July 1st. Similarly, the five days surrounding July 1st are plotted: June 29th, June 30th, July 1st, July 2nd, and July 3rd. The scatter plot of the ERA5 data is presented in Figure D - 53 below.

Figure D - 53: ERA5 Daily Average GHI vs Diurnal Temperature on June 29-July 3 for the West Solar Location



In Figure D - 53 above, for a given diurnal temperature range, there is a much smaller variance in the GHI compared to that in Figure D - 52. Furthermore, it is clear that as the diurnal temperature range (along the x-axis) increases the solar GHI (along the y-axis) tends to increase as well, and the ERA5 GHI seems to reach a plateau for higher diurnal ranges. The correlation coefficient here is much larger, about 0.85.

For each of the remaining 363 days of a year, the correlation coefficient is calculated between the ERA5 daily average GHI and the ERA5 diurnal temperature range for the 5 days surrounding the day of interest. From the resulting distribution of 365 correlation coefficients, the minimum, median and maximum are 0.45, 0.78, and 0.89, respectively. Thus, it could be concluded that, for any five consecutive days of a year, their ERA5 daily average GHI and diurnal temperature range, on average, are strongly correlated at the West solar location.[86]

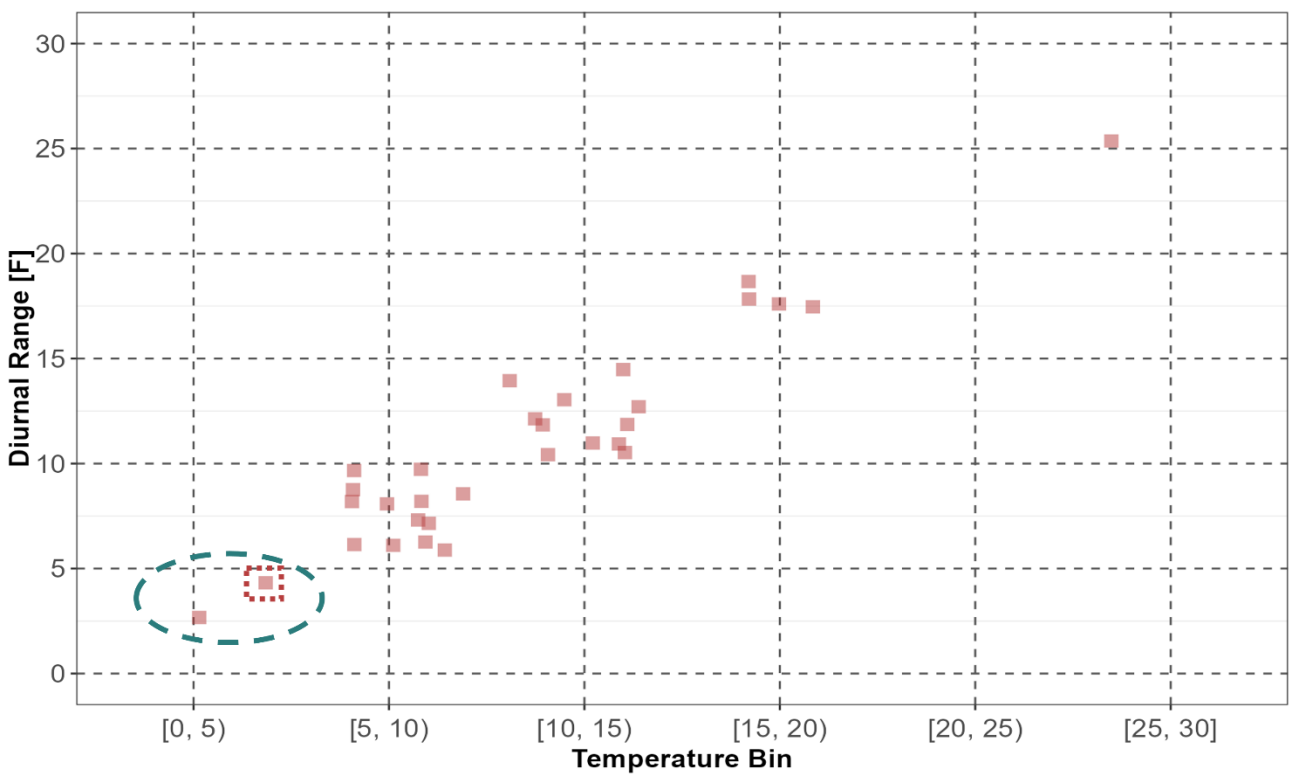
[86] For the "Central" solar location, the minimum, median and maximum correlation coefficients are 0.23, 0.62, and 0.80, respectively. For the "East" solar location, the three corresponding correlations coefficients are 0.32, 0.61, and 0.75, respectively. Therefore, for these two solar locations, the ERA5 GHI and diurnal temperature range are moderately correlated, for which the method developed in this section should apply.

Then, it is assumed that the climate scenario GHI and diurnal temperature range also have the same correlations as the ERA5 data sets. The method of using the climate scenario diurnal temperature range to estimate a climate scenario GHI is as follows. For a climate scenario date, for example, 3/4/2032, calculate its climate scenario diurnal temperature range, then randomly select a nearby diurnal temperature range (details to be presented in an example) from the distribution of ERA5 diurnal temperature ranges for the 5 days surrounding March 4th: March 2nd, 3rd, 4th, 5th, and 6th for the 43 years from 1980 to 2023. Then, the ERA5 hourly GHI data on the same date as the randomly selected ERA5 diurnal temperature range becomes the climate scenario hourly GHI for 3/4/2032.

This method is presented in more detail in the following example. For the West solar farm, download from the Climatology Lab's climate scenario A's daily minimum and daily maximum temperatures for climate scenario years 2019 to 2049.

For a specific day of a year, for example, January 1st, the first day of a year, there are 31 climate scenario dates: 1/1/2019, 1/1/2020, 1/1/2021, ..., 1/1/2049. The climate scenario A diurnal temperature ranges (DTRs) are calculated for the 31 climate scenario dates, and then categorized into temperature bins of size 5 F. For example, if DTR = 0.56 F, then it is categorized into the bin [0 F, 5F). If DTR = 12.3, then it is categorized into the bin [10 F, 15 F), etc. The 31 climate scenario A diurnal temperature ranges and temperature bins for the West solar farm are plotted in Figure D - 54 below.

Figure D - 54: Climate Scenario A Diurnal Temperature Range vs Temperature for West Solar Location for January 1



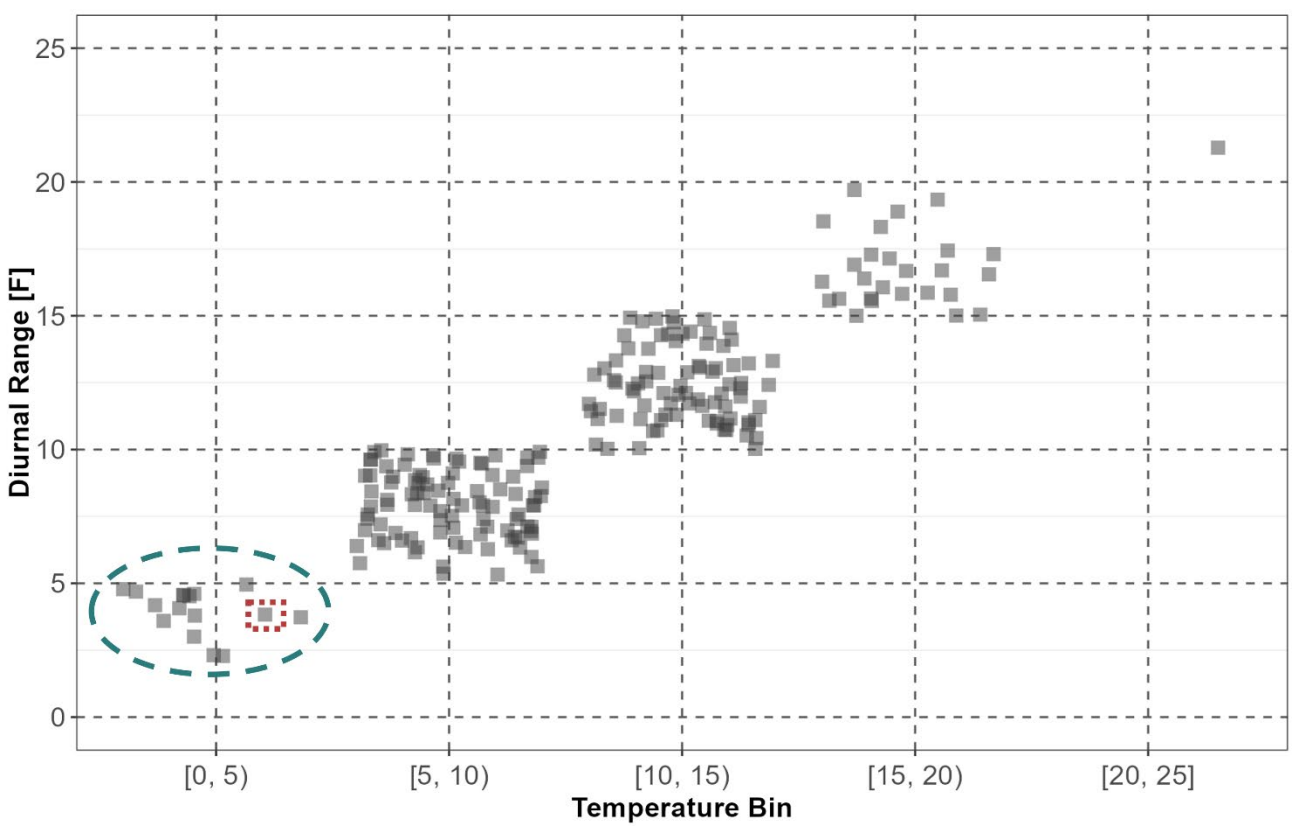
Along the x-axis in Figure D - 54, there are six temperatures bins in units of F, starting with [0, 5), which is followed by [5, 10), and so on, and ending with [25, 30]. All 31 climate scenario A's diurnal

temperature ranges are plotted along the y-axis and grouped into these six bins. For each of the 31 climate scenario A diurnal temperature range data points, there is a corresponding date of January 1st from 2019 to 2049. For example, in temperature bin [0 F, 5 F) at the left side of the x-axis, there are two climate scenario A DTRs, at 2.7 F and 4.3 F, plotted as red squares inside the dashed green oval. The DTR of 2.7 F corresponds to climate scenario date 1/1/2036, while the other DTR of 4.3 F corresponds to 1/1/2035. Interestingly, there is no DTR in temperature bin [20 F, 25 F).

Next, to estimate the climate scenario A GHI for either of the two DTRs in temperature bin [0 F, 5F) in the dashed green oval, randomly select a nearby ERA5 DTR (calculated for the West solar farm) from the five days surrounding January 1st: December 30th and 31st, January 1st, 2nd, and 3rd for the 43 historical years 1980 to 2023. Using the five days surrounding January 1st (instead of just January 1st) allows more ERA5 data to become available to be randomly selected. There are 220 (from five days surrounding January 1st $\times$ 43 years) ERA5 DTRs which were previously plotted in Figure D - 52.

Each of the 220 ERA5 DTR is then categorized into a temperature bin of size 5 F as was done for the climate scenario A DTRs. The 220 ERA5 DTRs and temperature bins for the West solar farm are plotted in Figure D - 55 below.

Figure D - 55: ERA5 Diurnal Temperature Range vs Temperature for West Solar Location for January 1



Thus, for the two climate scenario A DTRs in temperature bin [0, 5) in Figure D - 54 (inside the dashed green oval), the nearby ERA5 DTRs are those in the same temperature bin*, [0 F, 5 F),* in Figure D - 55

(inside the dashed green oval). There are 16 ERA5 DTRs in the [0, 5) bin in Figure D - 55 that could be randomly selected. Each of 16 ERA5 DTRs has a corresponding historical date which is listed in Table D - 25 below.

Table D - 25: The ERA5 Dates corresponding to the 16 Diurnal Temperature Ranges in the Temperature Bin [0 F, 5 F) in Figure D - 55.

The 16 ERA5 Dates in Temperature Bin [0 F, 5 F)
12/31/1992
12/31/1993
1/1/1997
1/1/2002
12/30/2002
1/3/2003
12/31/2003
1/1/2004
1/2/2004
1/3/2004
12/31/2005
12/30/2008
12/31/2008
12/31/2020
1/1/2021
1/2/2021

As an example, the 4.3 F climate scenario A DTR with corresponding climate scenario date 1/1/2035 (plotted inside the dashed red square and inside the dashed green oval in Figure D - 54) could be paired with a randomly selected ERA5 DTR plotted inside the dashed red square and inside the dashed green oval in Figure D - 55. The ERA5 DTR inside the dashed red square is 3.80 F and its corresponding historical date is 12/31/2005, which is listed in the bold font in Table D - 25. Therefore, the ERA5 hourly GHIs of that historical date, 12/31/2005, are assigned to be the climate scenario A hourly GHIs of climate scenario date 1/1/2035.

By pairing a climate scenario DTR with a randomly selected ERA5 DTR from the same temperature bin, the climate scenario date (corresponding to the climate scenario DTR) is thus paired with a selected ERA5 historical date (corresponding to the randomly selected ERA5 DTR). Finally, the climate scenario date would be assigned the ERA5 GHI hourly values of the randomly selected ERA5 historical date.

Therefore, using the method as presented in the example above, the cliamte scenario A GHI has been estimated for climate scenario date 1/1/2035. Following the same procedure, the climate scneario A hourly GHIs could also be calculated for the remaining 30 climate scenario dates for January 1st from 2019 to 2049.

It should be noted that the highest climate scenario A DTR, at 25.4 F, with a corresponding climate scenario date 1/1/2021, is catogorized into the highest temperature bin [25 F, 30 F] in Figure D - 54. However, in Figure D - 55, there is no ERA5 DTR data in temperature bin [25 F, 30 F]. In that case, the next closest ERA5 temperature bin is chosen, which is [20 F, 25 F] in Figure D - 55, and an ERA5 DTR within the temperature bin is randomly selected to pair with the highest climate scenario A DTR. But there is only one ERA5 DTR value in temperature bin [20 F, 25 F], which is 21.3 F and has a corresponding histoircal date 1/2/2012. Therefore, ERA5 24 hourly GHIs on 1/2/2012 are thus assigned to be the climate scenario A hourly GHIs on climate scenario date 1/1/2021.

Thus, this process assigns historical ERA5 hourly GHIs to all 31 January 1st for years 2019 to 2049 of climate scenario A plotted in Figure D - 54. The same process could be followed to assign ERA5 hourly GHIs to the remaining 364 calendar dates for years 2019 to 2049 of climate scenario A. Of course, using the same process would result in all the days in years 2019 to 2049 of climate scenarios C and G being assigned ERA5 hourly GHIs.

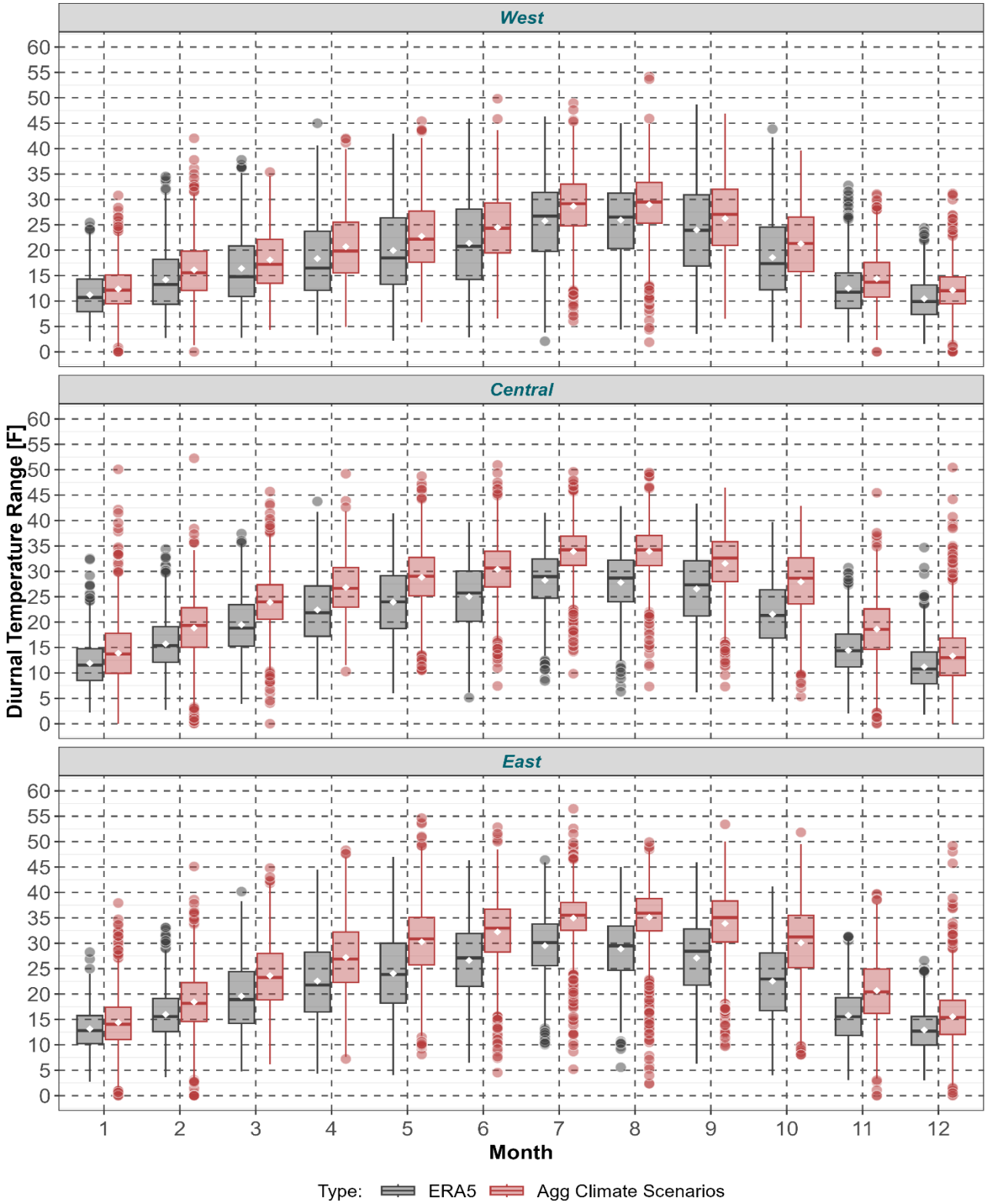
This methodology was presented to the CWAC.[87] Some climate scientists suggested further analysis of the climate scenario temperatures (which were used to calculate diurnal temperature ranges) to determine if there are biases. Another suggestion was to analyze for correlations between neighboring grid points. However, it was acknowledged that the analyses should be performed by climate scientists. Aside from these issues, there was no objection to the methodogly discussed in this section.

It is interesting to note in Figure D - 56 below that at each of the solar farm locations and for each month (along the x-axis), the aggregate climate scenario diurnal temperature range (plotted in the red boxplots) is higher than the ERA5 diurnal temperature range (plotted in the gray boxplots). It was also discussed in the RMJOC report that over the entire region, climate scenario temperatures (from 2020 to 2049) are higher than those in a historical time period.[88] It could be that the higher climate scenario temperatures are related to the higher climate scenrio diurnal temperature ranges.

[87] Climate and Weather Advisory Committee Meeting on 4/3/2025: https://www.nwcouncil.org/meeting/climate-and-weather-advisory-committee-2025-04-03.

[88] *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

Figure D - 56: Comparing ERA5 and Aggregate Climate Scenario Diurnal Temperature Range by Month at Each Solar Location

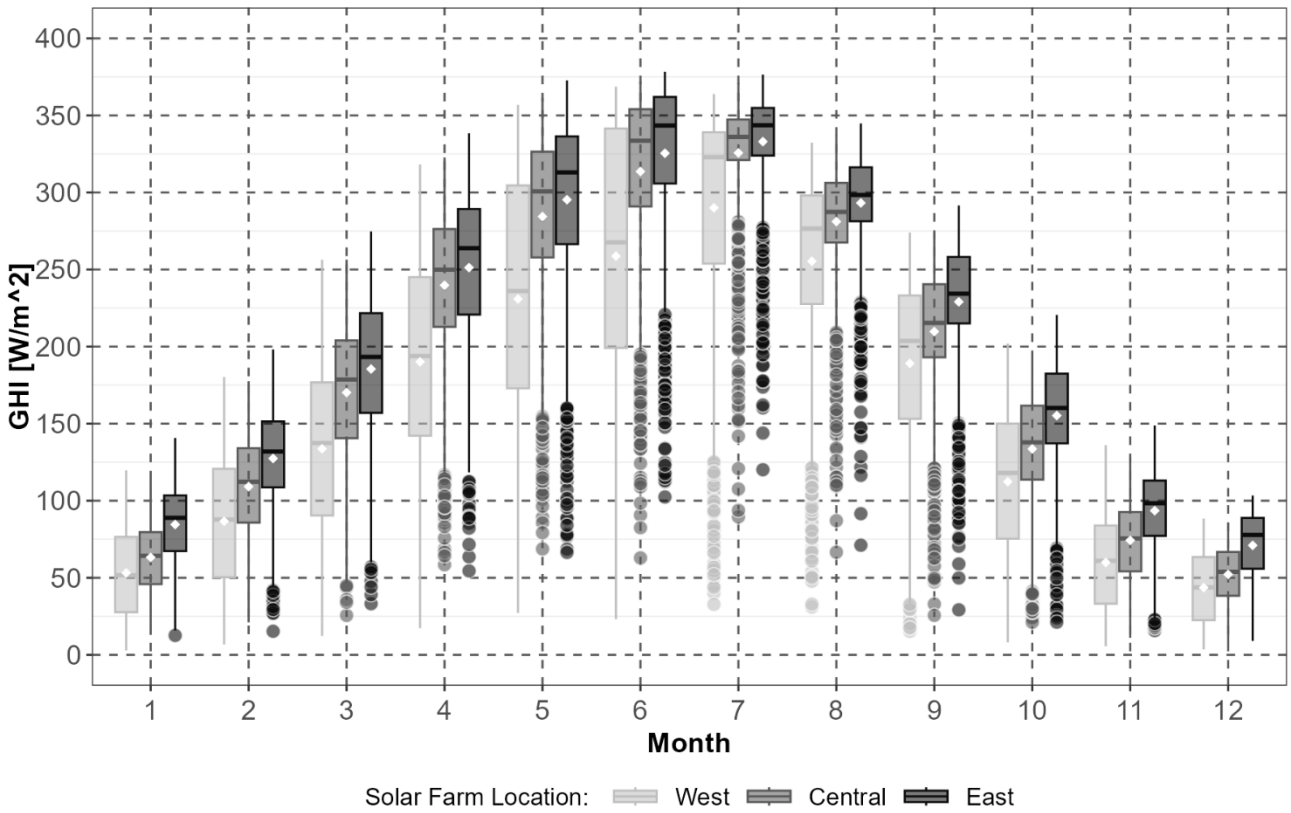


In any case, at each loaction and for each month, the distribution of climate scenario diurnal temperature ranges (red boxplots) are higher than the distribution of ERA5 diurnal temperature ranges (gray boxplots). Therefore, since the diurnal temperature range is highly or moderately correlated with GHI, then it could be deduced that the climate scenario GHIs will be higher than those of ERA5, at each location and for each month. This is discussed in the next section.

ERA5 and Climate Scenario GHI

The ERA5 hourly GHIs are embedded in the TSL model from 1980 to 2023, and their daily average GHIs at the three solar profile locations are plotted in Figure D - 57 below.

Figure D - 57: ERA5 Daily Range GHI by Month



There are two clear patterns in Figure D - 57. One is the pattern across the 12 months along the x-axis, with the maximum distributions occurring in July, and the minimum distributions in December, for each of the three solar locations. Therefore, the distributions of GHI increase from January to July and then decrease to December.

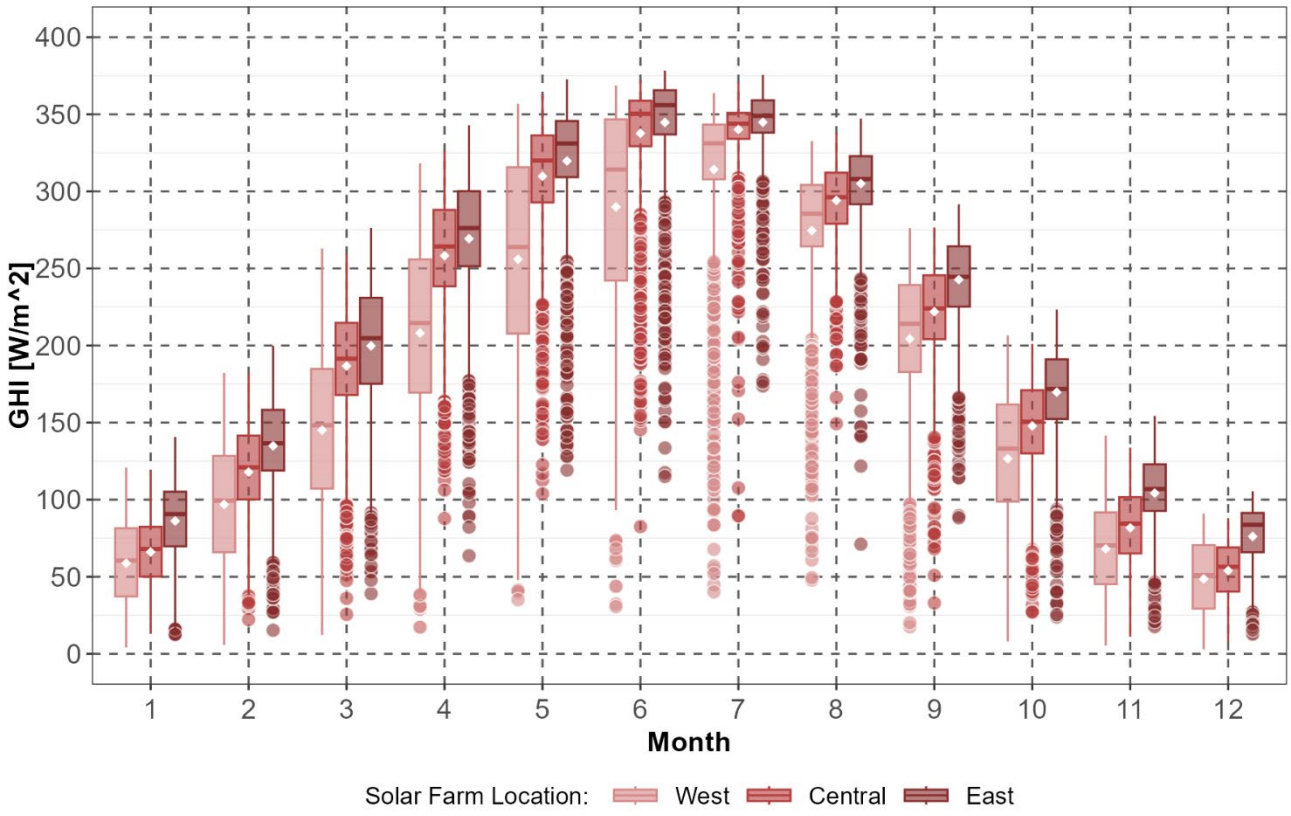
The other pattern is that for each month, the distribution for the West (plotted in light gray boxplots) is less than that for the Central (plotted in the medium gray boxplots), which in turn is less than that for the East (plotted in the dark gray boxplots). Furthermore, the variance for the West is higher than those for the other two locations, which are more comparable. Finally, even during the sunnier

months from months May to September, there are still some very cloudy days as plotted in the low boxplot outliers.

It turns out that the ERA5 GHI patterns in Figure D - 57 are transferred to the aggregate climate scenario (combined A, C and G) GHIs plotted in Figure D - 58. In the figure below, the same ERA5 geographical pattern in Figure D - 57 is evident: the distribution for the West (plotted in light red boxplots) is less than that for the Central (plotted in medium red boxplots), which in turn is less than that for the East (plotted in dark red boxplots). Also, for the 12 months along the x-axis, the other ERA5 monthly pattern is also clear: the distributions of GHI increase from January to July and then decrease to December.

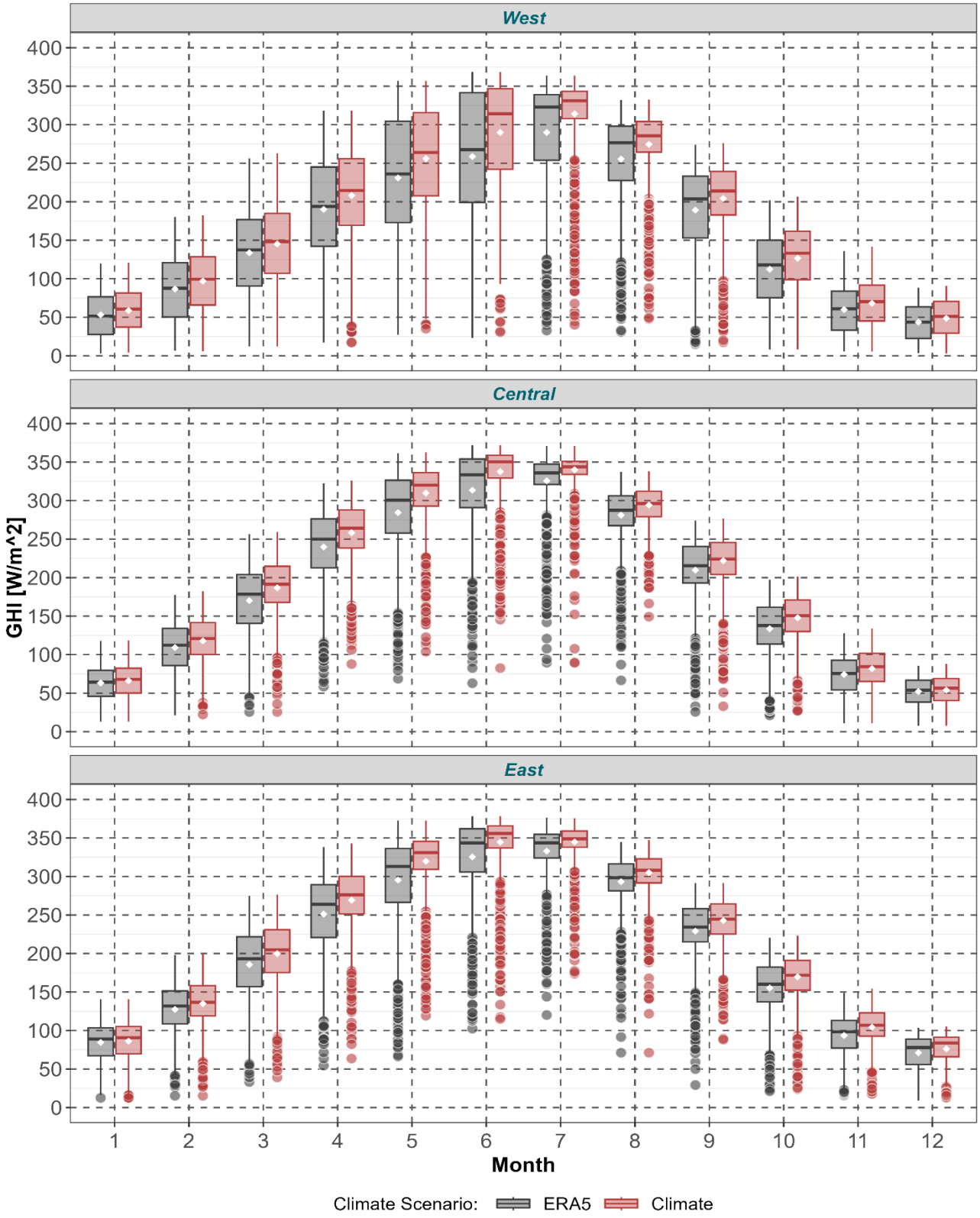
Therefore, these GHI patterns are expected to be preserved in the capacity factors as calculated by the TSL model (to be discussed in the next section).

Figure D - 58: Aggregated Climate Scenario Daily Average GHI by Month



However, despite having the same GHI patterns as the ERA5 data, the aggregate climate scenario GHIs, derived from sampling ERA5 data in matching diurnal temperature bins, are higher than ERA5 GHIs, as presented in Figure D - 59 for the three solar locations.

Figure D - 59: Comparison of ERA5 and Climate Scenario Daily Average GHI by Month



It is clear that at each solar farm location, the distributions of aggregate climate scenario GHIs are higher than those of ERA5 for all 12 months. The reason is that at each loaction and for each month, the distribution of climate scenario diurnal temperature ranges are higher than the distribution of ERA5 diurnal temperature ranges as presented in Figure D - 56 in a previous section. Therefore, climate scenario GHIs are assigned ERA5 GHI values from the matching higher ERA5 temperature bins which have higher ERA5 GHI values. Due to its higher GHIs, the aggregate climate scenario solar generation is expected to be higher than the ERA5 solar generation.

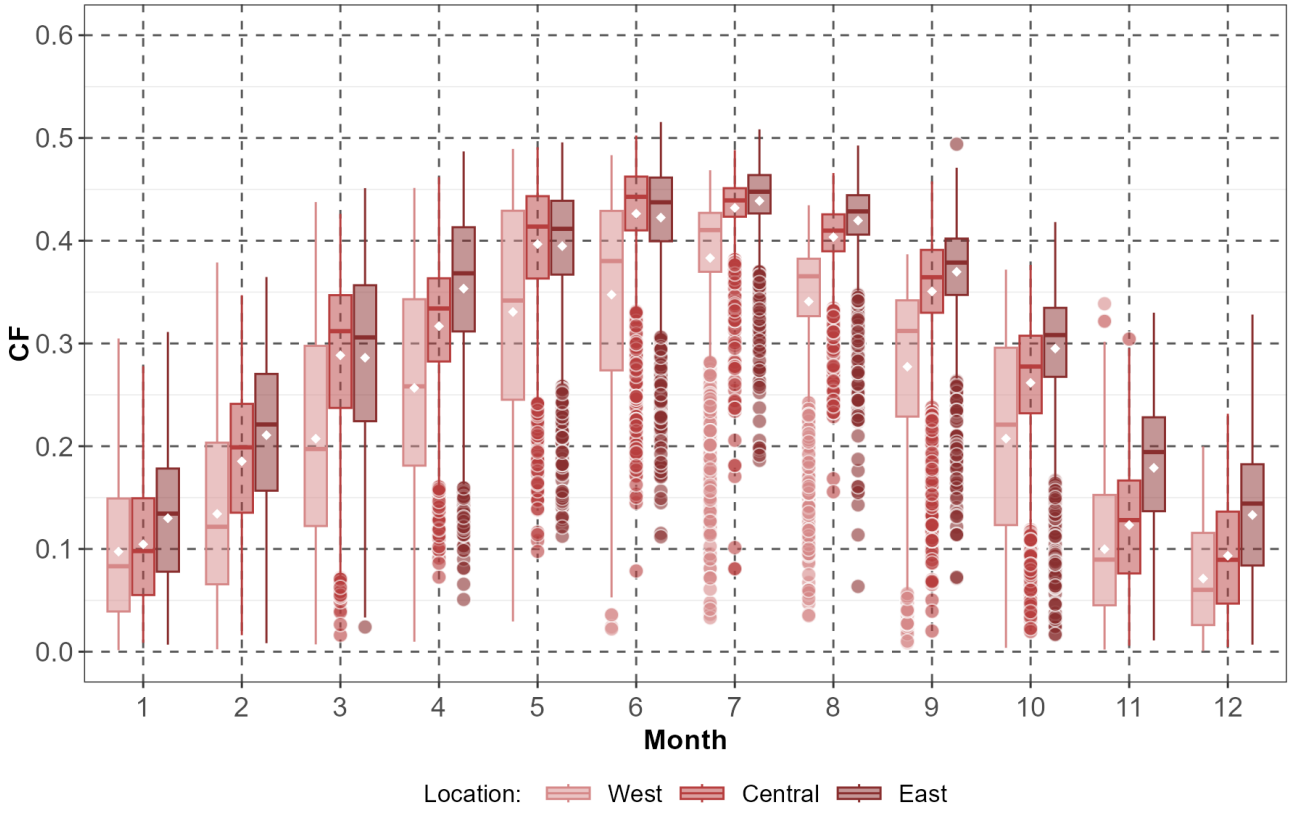
Climate Scenario Solar Generation

The climate scenario hourly solar GHIs whose daily averages are plotted in Figure D - 58 and Figure D - 59 are inputs into the TSL model to calculate solar generation for the 0-axis, or fixed, solar panel, and the 1-axis, or tilt, solar panel, which were chosen as reference plants for the Power Plan.[89] Both 0-axis and 1-axis panels are used for modeling existing utility scale solar generation. However, new utility scale solar generation are modeled with only the 1-axis panel. Furthermore, the 0-axis panel is used to model both existing and new behind-the-meter solar generation.[90]

In analyzing hourly solar generation data, there are many night-time hours for every day of a year where solar generation is zero, and the numerous zero CFs would distort the monthly boxplots of hourly CFs. Therefore, the daily average CFs are plotted instead. The aggregate climate scenario daily average generation capacity factors (CFs) for the 1-axis reference solar panel are plotted by month, along the x-axis, in Figure D - 60 below for the three solar locations.

[89] See Technical Appendix G - New Generating Resources in the Ninth Power Plan for more details.
[90] See Technical Appendix J - Rooftop Solar Methodology and Potential in the Ninth Power Plan for more details.

Figure D - 60: Aggregate Climate Scenario Daily Average Capacity Factors by Month



As discussed previously, the aggregate climate scenario GHI patterns in Figure D - 58 are mostly preserved in their CFs in Figure D - 60. The exceptions to the patterns are the distributions of Central CFs (in medium red boxplots) being about the same as those of the East CFs (in dark red boxplots) for the three months, March, May and June, whereas the East CFs were expected to be higher due to the East location having higher GHIs in Figure D - 58. This is due to bias-corrections on the climate scenario CFs to resemble historical solar CF data from the AURORA power system simulation model.[91] The bias corrections were performed internally in TSL.

The maximum daily average CF in Figure D - 60 is about 0.52 for the East solar farm for June, whereas the minimum is 0.0007 for the West solar farm for December. However, there are other CFs near the maximum and the minimum for other locations and other months.

In addition, the averages of the distributions (represented by the white diamonds inside each boxplot in Figure D - 60) are listed in Table D - 26.

[91] See https://www.energyexemplar.com/aurora.

Table D - 26: Averages of the Monthly Distributions of Solar Generation Capacity Factors

Month	West	Central	East
1	0.097	0.105	0.130
2	0.134	0.185	0.211
3	0.207	0.289	0.286
4	0.257	0.317	0.353
5	0.331	0.397	0.395
6	0.348	0.426	0.423
7	0.383	0.432	0.439
8	0.341	0.404	0.420
9	0.277	0.351	0.370
10	0.207	0.262	0.295
11	0.100	0.123	0.179
12	0.071	0.093	0.133

From Table D - 26, the maximum monthly average CF is 0.439 for July at the East solar farm, and the minimum is 0.071 in December at the West solar farm.

The overall annual average solar CFs for the West, Central, and East solar farms are listed in Table D - 27 below.

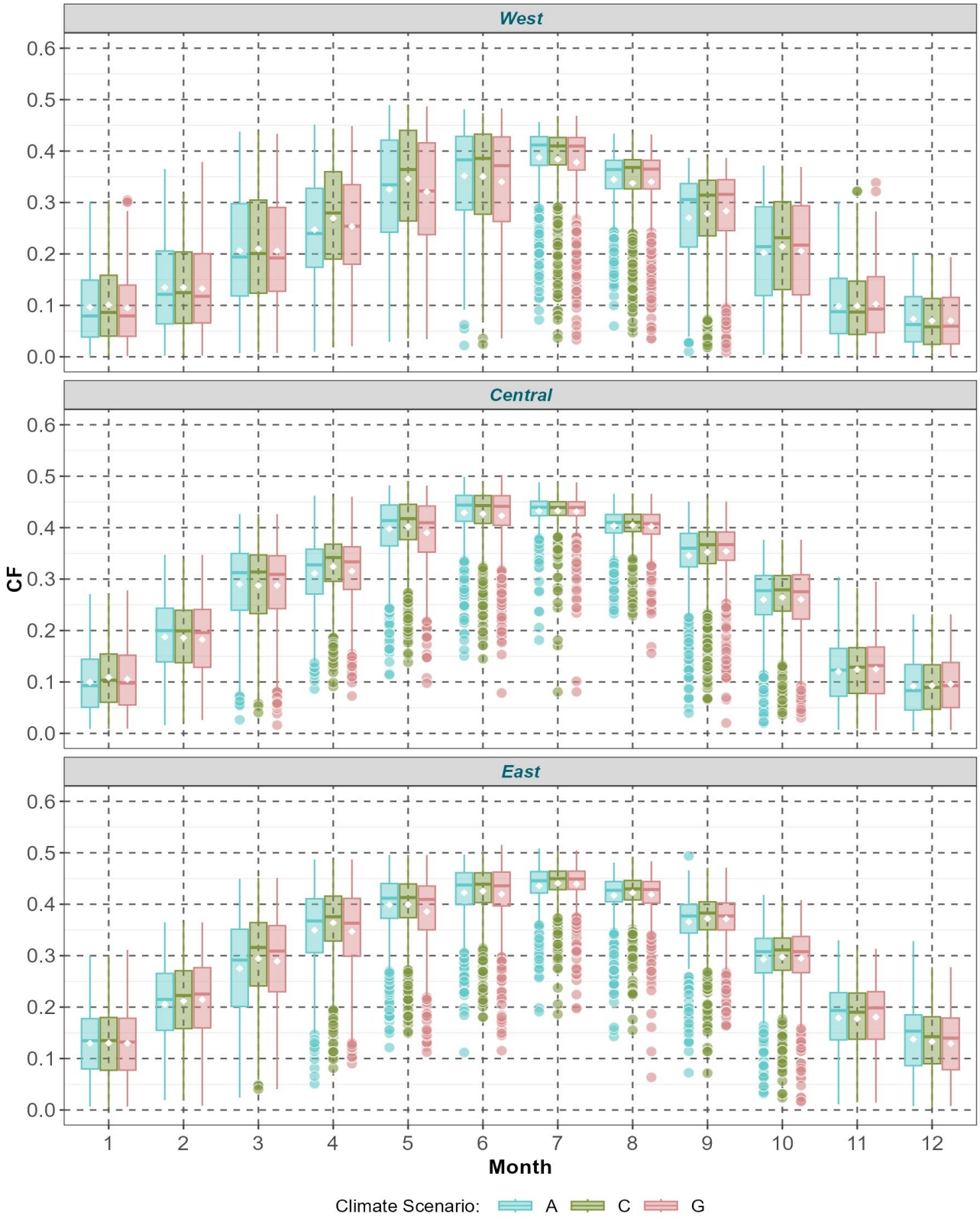
Table D - 27: Overall Averages of all Solar Generation Capacity Factors

Solar Farm Location	West	Central	East
Annual Average CF	0.230	0.282	0.303

The highest and lowest overall solar CFs are the East solar farm at 0.303 and the West solar farm at 0.230, respectively.

The boxplots in Figure D - 60 show the monthly and locational patterns of the aggregate climate scenario daily average solar CFs. There are small differences among the three climate scenarios in the plotted aggregate data. For completeness, daily average CFs by month of the three climate scenarios are plotted separately (instead of in-aggregate) for the three solar farm locations in Figure D - 61 below.

Figure D - 61: Monthly Average Solar Capacity Factors for Climate Scenarios A, C, and G



In Figure D - 61, solar CFs of climate scenarios A, C, and G are plotted in teal, green, and red boxplots respectively in each of the three panels. It could be seen that the differences among the climate scenarios are slightly higher for months April, May, September, and October. Otherwise, for other months at each location, the distributions of CFs among the three climate scenarios are closer to each other.

Very Low Climate Scenario Solar Generation

It is prudent to analyze the frequency and duration of very low solar generation (as was done for very low wind generation in a previous section) since during that stressful period, power system planners would have to develop a program to acquire sufficient and economical generation from other sources to meet load. As was done for very low wind generation, let very low solar generation at a solar farm be defined as those generations at or below the 10th percentile of all solar generations.

For simplicity, let the 10th percentile of all daily average CFs be represented by CF_{10}, and let those days where their CFs $\leq CF_{10}$ be referred to as low-CF days. For the three solar farms, their CF_{10}'s are listed in Table D - 28 below.

Table D - 28: The 10th Percentiles of the Distributions of Daily Average Solar Generation Capacity Factors over all Months.

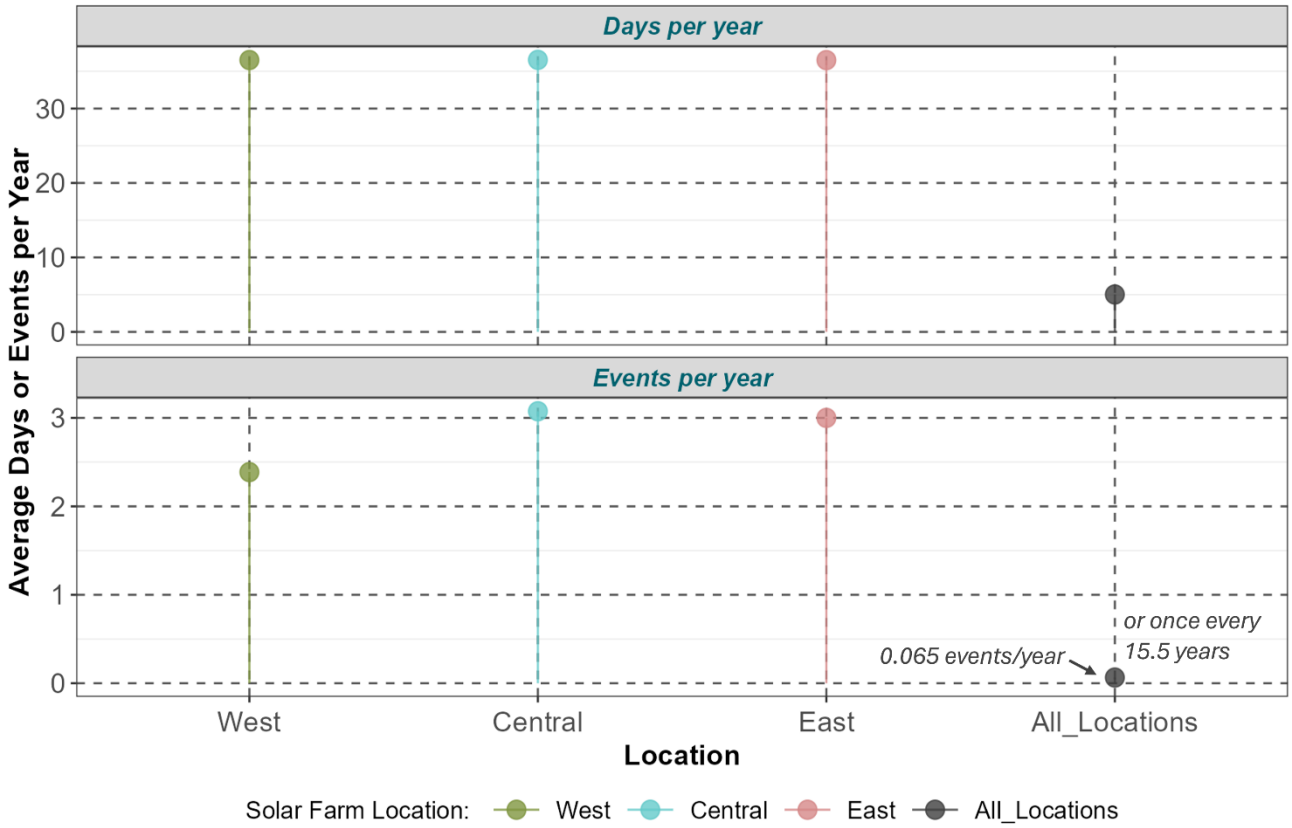
10th Percentiles of CFs	West	Central	East
CF_{10}	0.042	0.076	0.118

For the aggregate 93 climate scenario years, from the three climate scenarios each having 31 climate scenario years, there are a total of 33,945 days of daily average CFs. Therefore, the number of days where their daily average CFs $\leq CF_{10}$ is about 3,394, depending on the number of ties. Specifically for the West, Central, and East solar farms, there are 3,396, 3,398, and 3,395 low-CF dates, respectively. However, among the three sets of low-CF dates, there are only 467 low-CF dates common to all three solar farms, where on those common dates, the daily average CFs of all three solar farms are less than or equal to their respective CF_{10}'s listed in Table D - 28.

However, instead of analyzing the total number of low-CF days or dates for the 93 climate scenario years, a more interpretable quantity could be the average number of low-CF days per year. For example, for the West solar farm, the average number of low-CF days is $(3{,}396 \text{ days})/(93 \text{ years}) \cong 36.5$ days per year (where the daily average CF $\leq CF_{10}$). Furthermore, the average number of low-CF days common to all three solar farm is $(467 \text{ days})/(93 \text{ years}) \cong 5.02$ days per year.

In the top panel of Figure D - 62 below, the average number of low-CF days per year for the three solar farm locations and for All-Locations (all-three solar locations) are plotted.

Figure D - 62: Low Solar Periods in Climate Scenario Solar Profiles



There are on average 36.5 low-CF days per year for each of the three wind fleet locations: West (green circle), Central (blue circle), and East (red circle), listed from left to right on the x-axis. Furthermore, there is on average only around five common low-CF days per year for all three solar farm locations which is plotted in the gray circle on the right side.

Among the low-CF days could be subsets of three-or-more consecutive low-CF days, which are conditions under which it is even more challenging to operate the power system to meet load. Let the subsets of three-or-more consecutive low-CF days be referred to as low-CF events. For example, for the West solar farm, among the 3,395 low-CF days, there are 222 low-CF events (where each event consists of three-or-more consecutive low-CF days) in 93 climate scenario years. And for all three solar farm locations, out of the 467 common low-CF days, there are only 6 low-CF events.

In terms of average number of low-CF events per year, it is $(222 \text{ events})/(93 \text{ years}) \cong 2.39$ average number of events per year for the West solar farm. In contrast, there is only an average of $(6 \text{ events})/(93 \text{ years}) \cong 0.065$ low-CF events per year common to all three solar farms, which is rather infrequent.

Since (0.065 low-CF events per year) is less than (1 low-CF event per year), its reciprocal, $1/(0.065 \text{ events per year}) \cong (15.5 \text{ years per event})$, has an easier interpretation. In other words, for all three solar locations simultaneously having one common low-CF event, the frequency is on average once every 15.5 years.

In the bottom panel of Figure D - 62 above, the average number of low-CF events per year for the three solar farm locations and for all-locations are plotted. Going from left to right on the x-axis, the values are: West (green circle) 2.39; Central (blue circle) 3.08; East (red circle) 3.00; all-locations (gray circle) 0.065. As mentioned previously, for the entire in-region solar fleet to have very low generation that lasts for three or more consecutive days, that happens on average once every 15.5 years.

Furthermore, from Figure D - 60, the lowest monthly distributions of daily average CFs are in January and December. Therefore, it is not surprising that among all low-CF event days, the percentage of them being in January or December is: 77% for West; 82% for Central; 87% for East; and 100% for all-locations.

Out-of-Region Climate Data

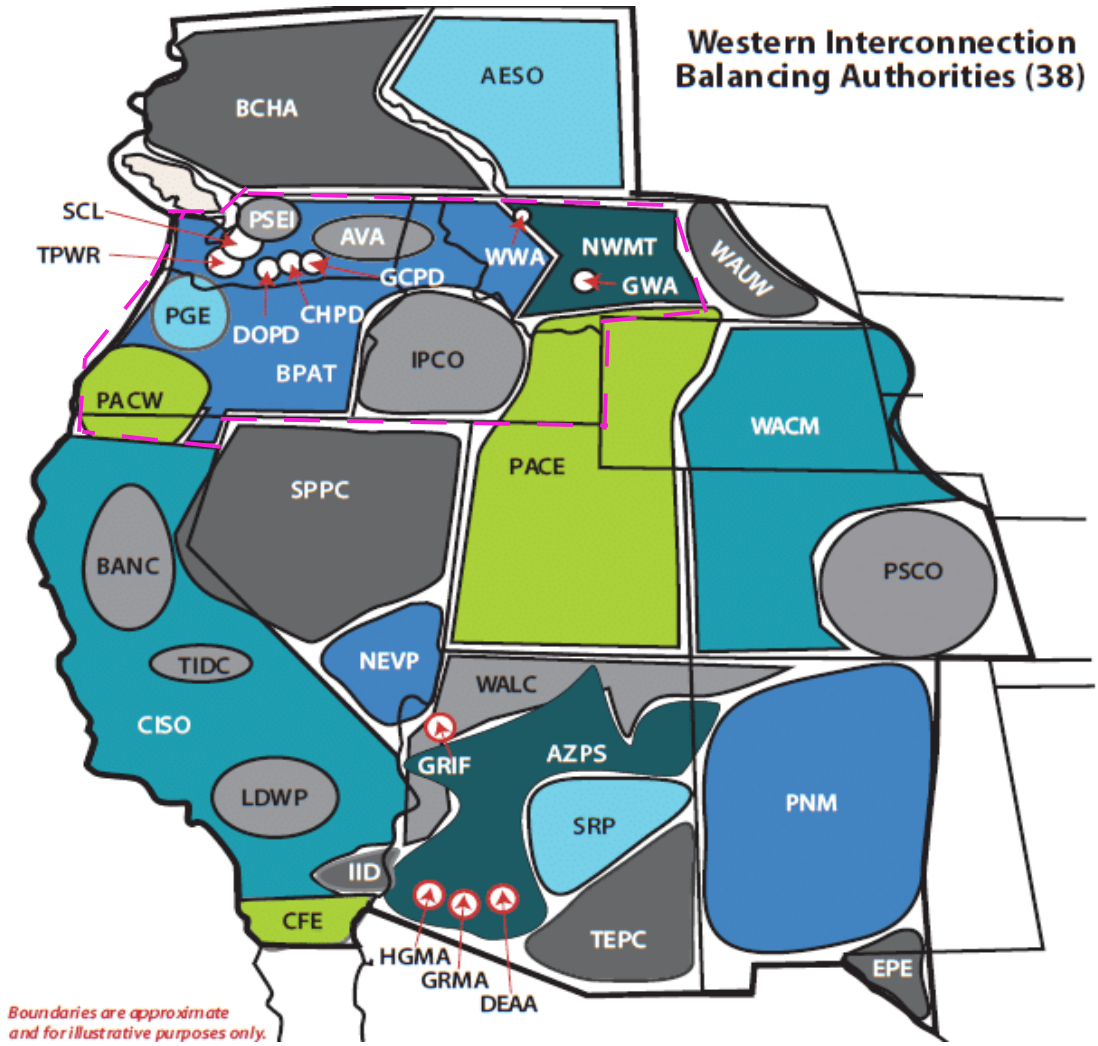
Previous sections of this Technical Appendix contain analyses of climate scenario temperatures, streamflows, wind and solar data for the Pacific Northwest. These data are considered as in-region and are inputs into the Council's analytical tools. Specifically, temperatures are inputs into the load forecast model ITRON, while streamflows, wind and solar data, along with the load forecasts, are inputs into the adequacy model GENESYS, and capital expansion model OptGen.

Since the Council's models also simulate operations of power systems in WECC that are outside of the Northwest, this section describes similar types of climate data used to model these out-or-region power systems. However, operations for these out-of-region power systems are simplified to enable reasonable model run-time.

Figure D - 63 below shows the 38 Balancing Authorities (BAs) in WECC, where those BAs (and portions of BAs) inside the area bounded by the pink dashed lines, for example, Portland General Electric (PGE in the light blue circle), represent in-region power systems.[92] In contrast, those BAs in Figure D - 63 that are outside the area bounded by the pink dashed lines, for example, Los Angeles Department of Water and Power (LDWP in the gray oval), represent out-of-region power systems. A list of all WECC BAs (and non-WECC BAs) and their acronyms are available on a Federal Energy Regulatory Commission (FERC) webpage.[93]

[92] Some generations in WAPA – Upper Great Plains (WAUW) and in the Wyoming portion of PACE are also considered as in-region.
[93] See https://mbrweb.ferc.gov/LookupData/LookupTables/lkp_baa?page=4.

Figure D - 63: The 38 Balancing Authorities in WECC



Temperature Data

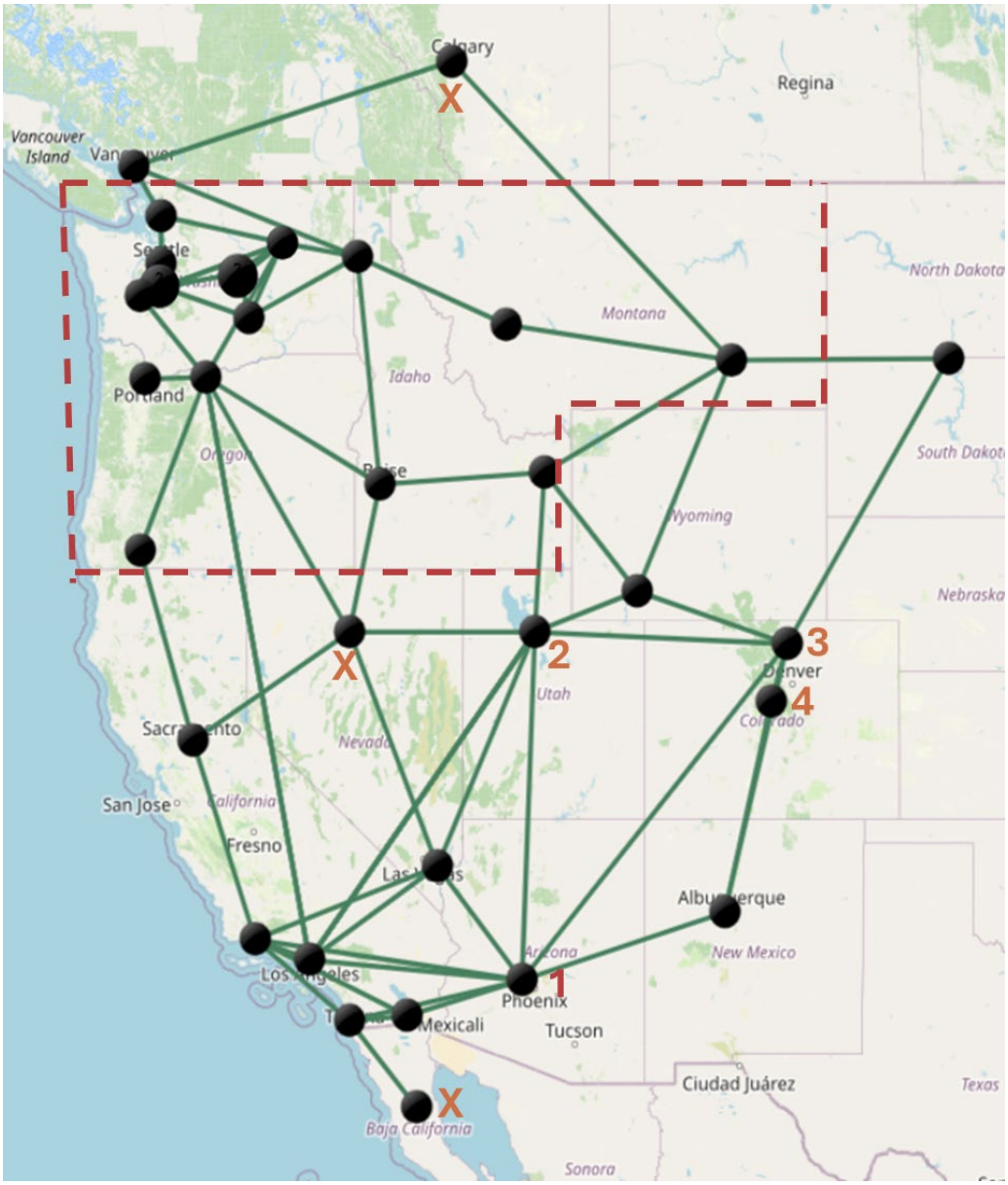
For out-of-region power systems, the Council decided to use load forecasts collected from utility planning documents such as Integrated Resource Plans (IRPs), Energy Information Agency (EIA) and Federal Energy Regulatory Commission (FERC) filings.[94] Therefore, there is no need to use any temperature data as inputs for out-of-region load forecasts.

[94] See Technical Appendix L - Wholesale Market Availability Results Draft for more details.

Streamflow Data

The out-of-region climate model streamflow data are calculated for 13 regions in WECC corresponding to a subset of transmission zones defined in the Council's GENESYS model and plotted in the black circles in Figure D - 64 below.

Figure D - 64: Zonal Transmissions in the GENESYS Model



In Figure D - 64, the transmission zones inside the area bounded by the dashed red lines are considered in-region, while those outside the bounded area are considered out-or-region transmission zones. All 13 streamflow regions are various combinations of the out-of-region transmission zones, except those labeled with an orange "X."

A streamflow region could correspond to one transmission zone, for example, the transmission zone in Arizona, labeled by the orange "*1*" in Figure D - 64. This one zone comprises four WECC BAs plotted in Figure D - 63: Arizona Public Service (AZPS), Salt River Project (SRP), Tucson Electric Power (TEPC) and WAPA Lower Colorado (WALC).

Another streamflow region corresponding to one transmission zone is the one in Utah labeled by the orange "2" in Figure D - 64. However, this zone is not an entire WECC BA but a subset of the WECC BA PacificCorp East (PACE in Figure D - 63).

On the other hand, some streamflow regions correspond to combinations of multiple transmission zones. For example, the streamflow region in Colorado consists of two transmission zones labeled by the orange "3" and "4" in Figure D - 64. Respectively, they represent WECC BA WAPA Rocky Mountain (WACM in Figure D - 63) and WECC BA Public Service Company of Colorado (PSCO in Figure D - 63).

The remaining 10 of 13 streamflow regions are defined very similarly to the three examples above, which is, one or more of the transmission zones plotted in Figure D - 64 which in turn correspond to one or more WECC BAs (see Figure D - 63), or one or more subsets of WECC BAs, or both WECC BAs and subsets of WECC BAs.

Therefore, to model (out-of-region) hydro systems in the 13 streamflow regions, the Council decided to use hydro generations from the GODEEEP data set[95] developed by the Pacific Northwest National Lab (PNNL). The GODEEEP hydro generations are calculated from streamflow data (but not available in GODEEEP) derived from hydrological modeling of an ensemble of CMIP6 climate models.[96] The ensemble of CMIP6 climate models, published around 2020 or shortly after, are newer than the 10 CMIP5 models (published around 2012) that were used to produce the in-region RMJOC climate data as presented in previous sections.[97] Despite differences between the CMIP5 and CMIP6 climate models, as the climate data outside the region is disjointed from climate data inside the region, the Council decided to use the ensemble CMIP6 data because they should contain more up-to-date general trends of climate change.

For simplicity, for each of the 13 streamflow regions, all hydro generations within the region are added together to become the total hydro generation of that region. Furthermore, by assuming the total hydro generation of a region is produced by *just one* hypothetical hydro-project with a fixed (constant) power production coefficient (e.g., the H/K factor), then a representative CMIP6 "streamflow" of a

[95] See https://zenodo.org/records/13776945

[96] See https://www.nature.com/articles/s41597-025-05097-3.pdf, https://www.nature.com/articles/s41597-023-02485-5 , and https://www.nature.com/articles/s41597-023-02485-5/tables/1.

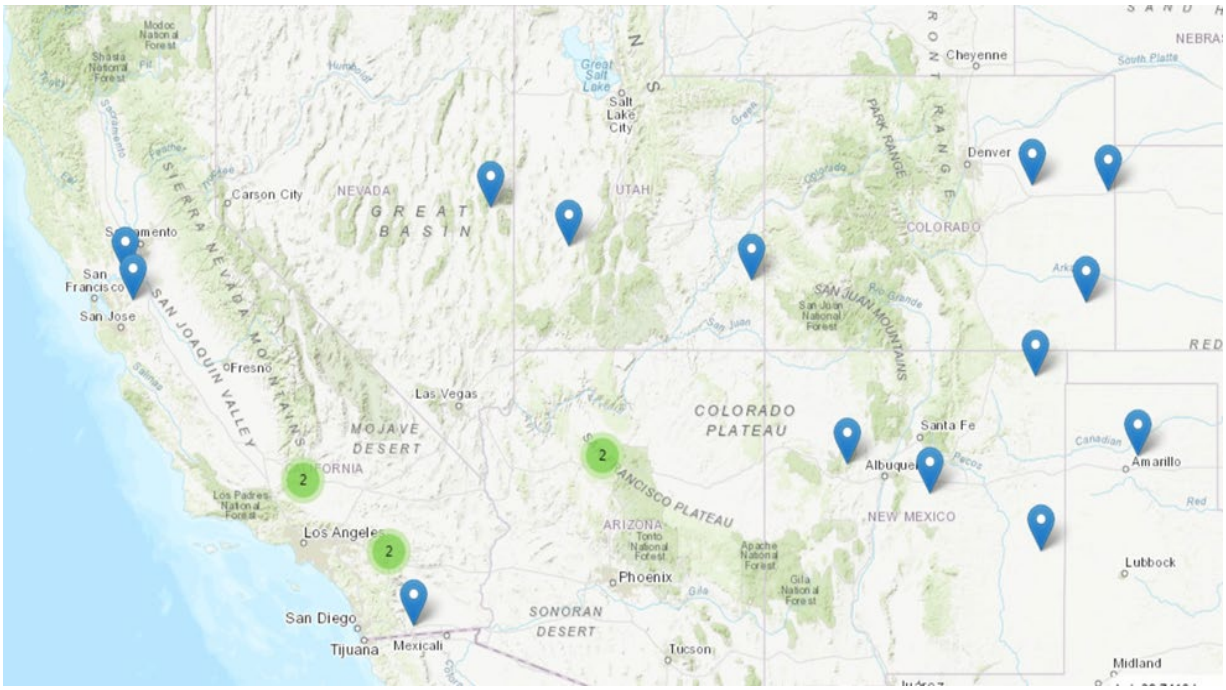
[97] See "*CMIP6 - Coupled Model Intercomparison Project Phase 6*" at https://pcmdi.llnl.gov/CMIP6. It should be noted the CMIP6 models are different from CMIP5 models, even those with very similar names developed by the same organizations (e.g., GFDL-ESM*, or CNRM-CM*). Therefore, even on the same calendar date (i.e., 6/15/2032) the CMIP6 out-of-region climate data should not be expected to be temporally co-incident to the CMIP5 in-region climate data.

region could be calculated as a ratio. The representative CMIP6 streamflows for the 13 regions then become inputs into the Council's GENESYS and OptGen models.

Wind Data

For out-of-region on-shore wind generation, the Council decided to simulate generation at the 20 locations plotted in Figure D - 65 below.

Figure D - 65: The 20 Locations for Modeling Out-of-Region On-Shore Wind Generation



In Figure D - 65, the three green circles with the number "2" indicate that there are two wind turbine hub-heights and thus two wind generation shapes modeled at those locations. The remaining 14 locations have only one wind turbine hub-height and so only one wind generation shape.

In addition to the onshore wind generation, the Council also simulates out-of-region offshore wind generation at the six locations plotted in Figure D - 66 below.

Figure D - 66: The Six Locations for Modeling Out-of-Region Off-Shore Wind Generation

The upper two locations in Figure D - 66, offshore from the Oregon coast near Coos Bay and Brooking, could be considered as in-region. However, since at these two locations there is no CMIP5 model wind speed available from the Climatology Lab,[98] then for simplicity, they are grouped with the lower four locations off-shore from the California coast as out-of-region wind farms.

[98] Climatology Lab: https://www.climatologylab.org/maca.html.

Due to time constraint of the Power Plan, it was not feasible to incorporate climate model wind generation from the GODEEEP data set[99] at the locations plotted in Figure D - 65 and Figure D - 66 into the Council's simulation models, as was done for climate model hydro-generation discussed in the previous section.

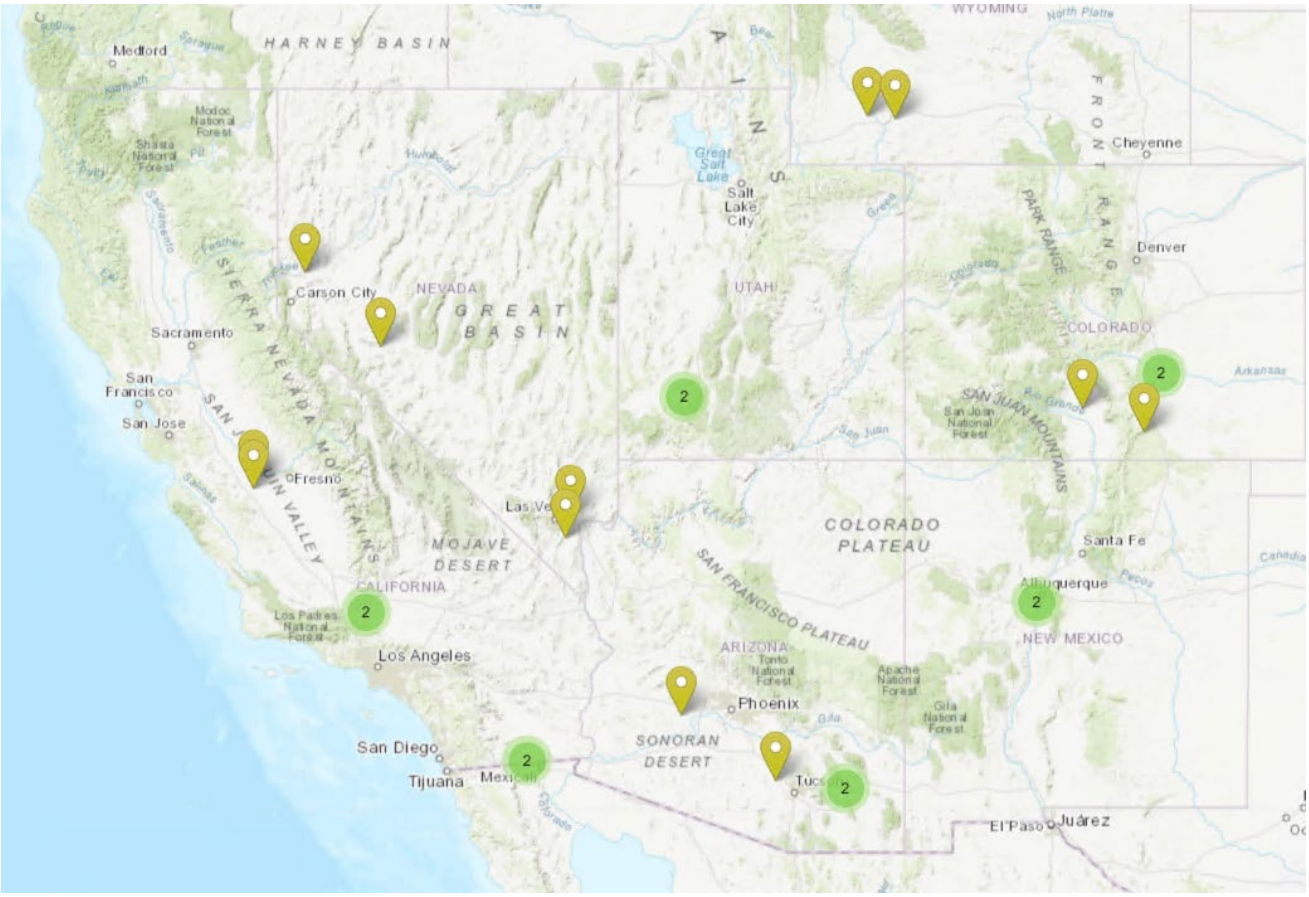
For the Ninth Power Plan, the Council decided to use the bias-corrected historical ERA5 wind data set which is already embedded in the TSL model[100] to calculate wind generation capacity factors at the 26 locations for various reference wind turbines.[101] Similar to the development of in-region wind generation data presented in the Section "Climate Scenario Wind Generation Profiles," the historical out-of-region on-shore ERA5 wind data were bias-corrected to be similar to historical wind generation profiles (at the 20 locations plotted in Figure D - 65) from the AURORA power system simulation model[102] and the National Wind Tool Kit[103] developed by the National Lab of the Rockies. In contrast, the historical off-shore ERA5 wind data were bias-corrected to be similar to historical wind generation profiles (at the six locations plotted in Figure D - 66) downloaded from the Bureau of Ocean Energy Management (BOEM) website.[104]

Solar Data

For out-of-region solar generation, the Council decided to simulate generations at the 24 locations plotted in Figure D - 67 below.

[99] See https://zenodo.org/records/13717258
[100] See https://www.timeserieslab.com for more details.
[101] See Technical Appendices B - Existing System Parameters and Policies Draft and G - New Generating Resources Draft for more details.
[102] AURORA power system simulation model: see https://www.energyexemplar.com/aurora.
[103] National Wind Toolkit: see https://www.nlr.gov/grid/wind-toolkit.
[104] Bureau of Ocean Energy Management (BOEM): see https://www.boem.gov/renewable-energy/mapping-and-data/renewable-energy-gis-data.

Figure D - 67: The 24 Locations for Modeling Out-of-Region Solar Generation



In Figure D - 67, the six green circles with the number "2" indicate that there are two types of solar-panel axis (fixed and 1-axis) and thus two solar generation shapes modeled at those locations. The remaining 12 locations have only one type of solar panel axis and so only one solar generation shape.

Similar to modeling the out-of-region wind generation, for the Ninth Power Plan, the Council also decided to use the bias-corrected historical ERA5 solar data set which is already embedded in the TSL model to calculate solar generation capacity factors at the 18 locations for various reference solar panels.[105] The historical out-of-region ERA5 solar data set were bias-corrected to be similar to historical solar generation profiles (at the 18 locations plotted in Figure D - 67) from the AURORA power system simulation model.[106] It should be noted that six solar generations in California have been adjusted to account for wildfire effects.[107]

[105] See Technical Appendices B - Existing System Parameters and Policies Draft and G - New Generating Resources Draft for more details.
[106] AURORA power system simulation model: see https://www.energyexemplar.com/aurora.
[107] See wildfire methodology section in Technical Appendix G - New Generating Resources Draft for more details.

Technical Appendix E: Thermal Fuels Forecast

Contents

Thermal Fuels in the Northwest Power System 1
Natural Gas in the Northwest Power System 2
Natural Gas Price Forecast 5
Natural Gas Transportation Cost 7
Detailed Gas Prices for the Ninth Plan 8
Renewable Natural Gas 8
Coal in the Northwest Power System 8
Coal Price Forecast 9
Detailed Coal Prices for the Ninth Plan 10
Fuel Oil in the Northwest Power System and Price Forecast 10
Nuclear Power in the Northwest Power System & Fuel Forecast 10
Fuel Related Emissions 11
Existing System Emissions 11
Upstream Methane Emissions 11

Thermal Fuels in the Northwest Power System

The Northwest electric power system runs on a mix of generating technologies. While hydroelectric generation is the largest contributor to the mix, thermal generation plays an important role both for annual generation and during extreme weather events. Table E - 1 shows how much electricity was generated in the Northwest by different resource types in 2024 on an annual basis. Thermal resources are highlighted in light red. The table shows total in-region generation and excludes imports and exports, although the region has been a net exporter on an annual basis in recent years. During high

demand events the proportion of energy coming from thermal resources often increases compared to annual energy.[1]

Table E - 1: Annual Energy Generation in the Northwest, 2024[2]

Fuel type	Annual energy (aMW)	Percent
Hydro	12,110	48%
Natural gas	6,080	24%
Wind	3,110	12%
Coal	2,030	8%
Nuclear	1,140	4%
Other	480	2%
Solar	440	2%
Fuel oil	10	0.04%

Natural Gas in the Northwest Power System

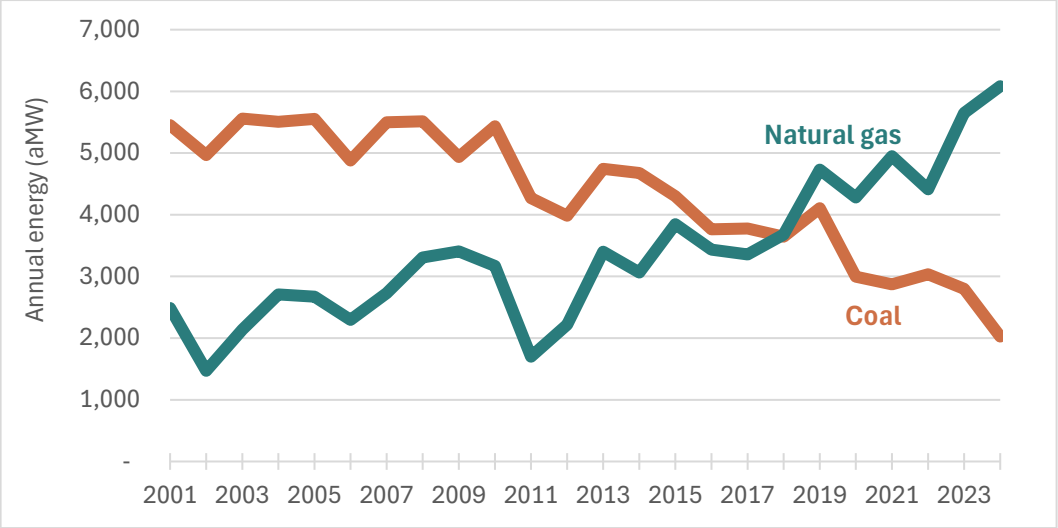
Natural gas is the main thermal fuel used to generate electricity in the Northwest power system today. Its role has grown in the past few decades as illustrated in Figure E - 1, with annual energy from gas generation surpassing coal generation in 2018. Part of this growth is due to an increase in total natural gas generating capacity, with the Northwest adding thousands of megawatts of new nameplate capacity in the 2000s. Part of this growth, especially in recent years, is due to increased utilization of the existing system: from 2016 to 2023 no new natural gas power plants came online, yet annual generation grew. In 2024, Northwest natural gas capacity increased via the new Yellowstone reciprocating engine facility in Montana, and the Jim Bridger coal to gas conversion in Wyoming.[3] Please see Technical Appendix B – Existing System and Polices for more discussion on the existing natural gas power plant fleet.

[1] For an example of this please see the Council discussion on the January 2024 high stress event: https://www.nwcouncil.org/fs/18649/2024_03_5.pdf.

[2] EIA data. Includes total electric power industry generation in the states of ID, MT, OR, WA, 100% output from Jim Bridger (located in WY) and 50% of North Valmy (located in NV). The data are for year 2024 which was a below average hydro generation year, which often leads to higher levels of thermal generation.

[3] Although Wyoming is geographically not in the Northwest footprint as defined by the Power Act, Jim Bridger is a resource that serves Northwest load.

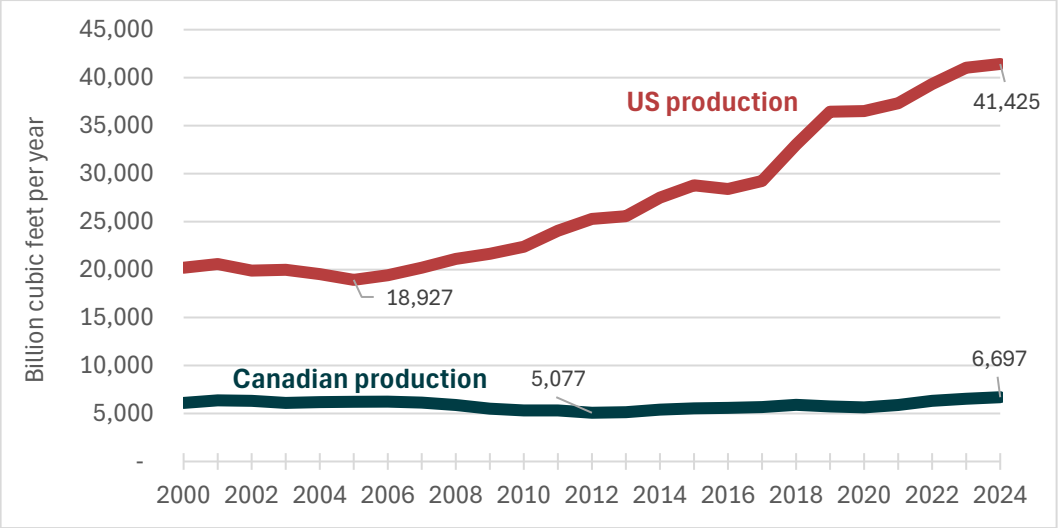
Figure E - 1: Natural gas and coal generation in the Northwest, 2001-2024



The Northwest imports natural gas from Canada and the greater US, with most of the imports coming from Canada.[4] Both the US and Canada have seen increases in natural gas production in the last decade. Much of the growth in production is due to increased use of horizontal drilling and hydraulic fracturing. Today, the majority of US gas is produced using this method.[5] Figure E - 2 below shows total Canadian and US marketable gas production from 2000 through 2024, with the production lows and highs in that time frame labeled. Today, the US is the top natural gas producer in the world, with Canada ranked number five.[6]

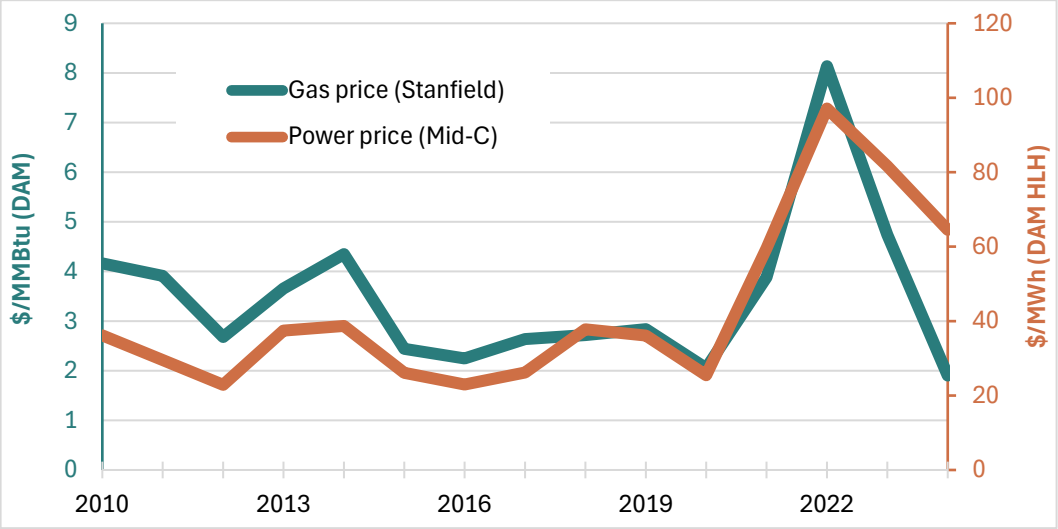
[4] Northwest Gas Association 2024 Outlook: https://d588fb10-0cdf-4398-b6a6-77beee46f98e.filesusr.com/ugd/054dfe_da78848821a448c1b897a5a32d94cbd8.pdf.
[5] US EIA: https://www.eia.gov/tools/faqs/faq.php?id=907.
[6] US EIA: https://www.eia.gov/international/rankings/country/USA?pid=4413&aid=1&f=A&y=01%2F01%2F2023&u=0&v=none&pa=287.

Figure E - 2: US and Canadian annual marketed natural gas production[7]



Natural gas is often the fuel on the margin for the power market. As a result, power prices, which are typically associated with the marginal resource cost, are highly influenced by the price of natural gas. This relationship is shown in the figure below which compares the annual average price of natural gas at Stanfield, a Northwest hub, and power at Mid-Columbia, a common Northwest trading point. Going forward, as more variable energy and storage resources are expected to arrive in the Western power system, this relationship may weaken if gas is on the margin for fewer hours.

Figure E - 3: Average annual gas and power price relationship in the Northwest



[7] US data from the US EIA: https://www.eia.gov/dnav/ng/hist/n9050us2a.htm Canadian data from Canada Energy Regulator: https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/natural-gas/statistics/marketable-natural-gas-production-in-canada.html.

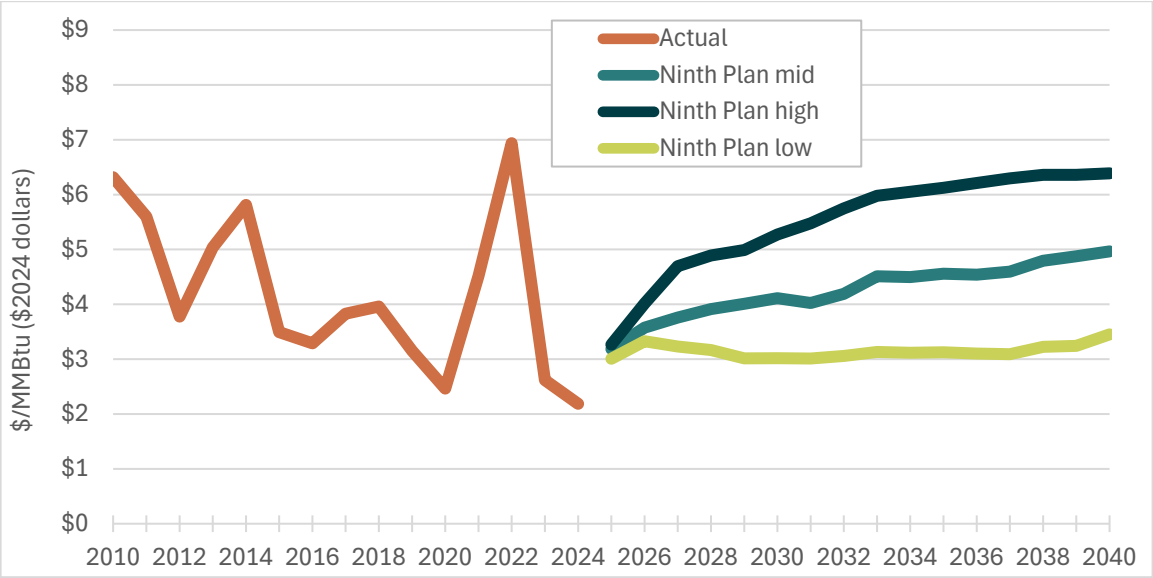
Natural Gas Price Forecast

The Council has an established methodology for forecasting natural gas prices. It is outlined in the steps below. Compared to past Council gas price forecasts, step 6 is implemented slightly differently in the Ninth Plan.

1. Surveys are sent to the members of the Fuel Advisory Committee asking for annual natural gas price forecasts at Henry Hub at a low, medium, and high levels; publicly available forecasts from the US EIA and the California Energy Commission are collected as well
2. The price forecasts are aggregated, and the median (50th percentile) forecast for each year is selected as the starting price for the Council forecast
3. The first few years of the price forecast is blended with a futures strip (CME Group)
4. The Henry Hub forecast is translated to western hub forecasts using historical price deltas
5. Input from the Committee is solicitated – for the Ninth Plan one key input was to increase prices at select hubs in years 2027 through 2029 due to liquified natural gas (LNG) developments in the West
6. Monthly shaping and volatility are added to each hub based on the past 10 years of historical data (this step is different than the monthly shaping and volatility step in the 2021 Power Plan)
7. The forecast with volatility is shared with the Committee for feedback
8. The forecast is shared with Council members for finalization

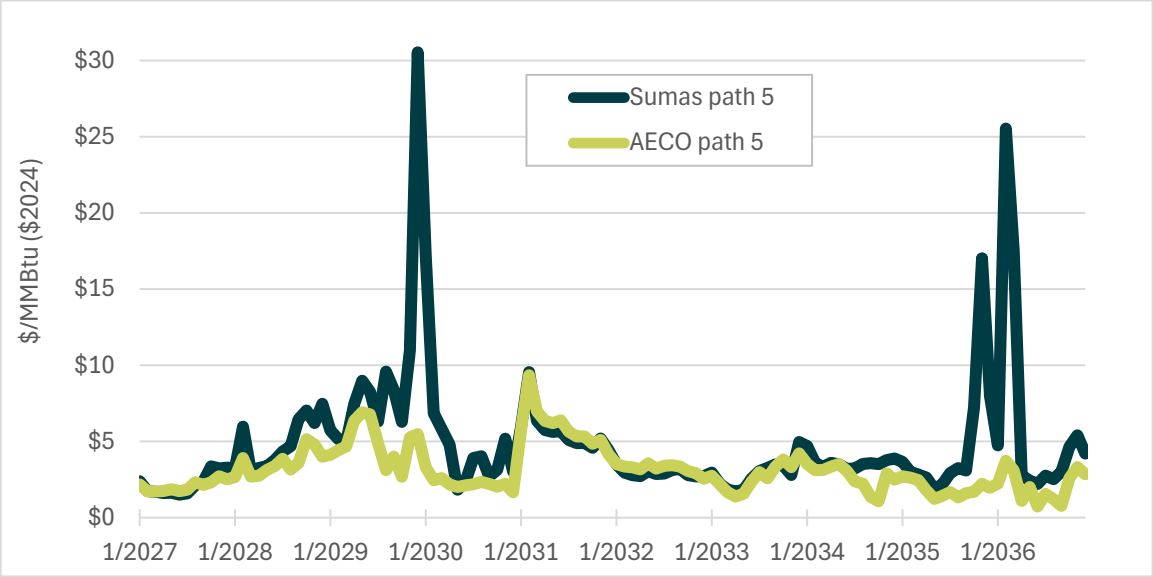
The final annual low, mid, and high Henry Hub forecasts are shown below in real 2024 dollars. For comparison, historical prices at Henry Hub are included.

Figure E - 4: Low, Mid, and High Natural Gas Price Forecasts (Henry Hub)



For modeling, there are ten different volatility pathways available (the pattern shifts one-year in each pathway) for the low, medium, and high forecasts. This results in 30 different forecasts in total. Due to the volatility patterns, the median (50th percentile) forecast ends up being lower than the mean (average) forecast. Figure E - 5 below shows one monthly hub level forecast pathway (path five) from the Sumas and AECO hubs. As seen in the figure, in recent years, Sumas gas has traded at a premium to AECO and has had greater volatility.

Figure E - 5: Volatility in Gas Price Forecasts Example



Going forward, the Fuels Advisory Committee is more concerned with pipeline capacity and congestion leading to high prices rather than total gas supply (this sentiment is not necessarily universally shared among Committee members). In the figure above, the gas price excursions are tied to historical events. While the Council does not expect these same events to occur again, they are used as proxies for potential future events.

Regarding future price events, the Fuels Committee expressed concerns that LNG export facility development in the West could put upward price pressure on Western hubs. To date, most North American LNG export facilities have been located on the Gulf of Mexico or the US East Coast.[8] The Committee discussed three Western facing LNG export facilities, and their potential to impact Northwest prices, in lead up to the Ninth Power Plan. The LNG developments that the Committee focused on are below. For scale, the Northwest used around 360 BCF of gas for power generation in 2024:

a) Woodfibre LNG, located roughly 40 miles north of Vancouver, British Columbia (approximate export capacity of 675 BCF/year). At the time of forecast publication, the project was expected online around 2027. It will source gas from near the Sumas hub. Committee

[8] US EIA: https://www.eia.gov/todayinenergy/detail.php?id=66384.

members expressed concerns that this will cause pipeline constraints and competition for gas at the Sumas hub. As a result, a price adder was put into the forecast from 2027 through 2029, at which point a pipeline expansion is expected to relieve congestion.

b) LNG Canada, located in Kitimat, British Columbia (approximate export capacity of 100 BCF/year). At the time of forecast publication this project was nearly done with construction and entering start up and testing. It will source its natural gas from the 416-mile-long Costal GasLink pipeline that runs from the facility to near Dawson Creek, close to the British Columbia and Alberta border. Although the project is much larger than the Woodfibre LNG project, a price adder was not included in the forecast for it. This is due to the additional pipeline capacity that accompanies the project, and the expectation that Alberta and British Columbia will be able to increase gas production to support the project.

c) Costa Azul, located near Ensenada, Baja California (approximate export capacity of 150 BCF/year). At the time of forecast publication this project was expected online in 2025 (this timeline has moved to 2026). Although not physically close to the Northwest, there are concerns that this facility could increase pipeline congestion into the California market, which would in turn increase California's demand on natural gas from the Northwest, impacting regional prices.

Natural Gas Transportation Cost

Natural gas is transported from hubs to generators via pipelines. At times, multiple pipeline segments are used to move the commodity. There is a cost associated with using pipelines to transport gas. This cost is considered in the Council's power planning models. For simplicity, the Ninth Plan assumes that it costs $0.40/MMBtu to move gas from a hub to a generator.

The $0.40/MMBtu transportation cost assumption is an oversimplification: actual costs will vary depending on the generator location and the hub the gas is purchased from. Council staff considered exploring a more sophisticated gas transportation cost allocation in the Ninth Plan, but decided against it due to time constraints and challenges with gathering the data. The $0.40/MMBtu value was discussed with the Fuels Committee who agreed it worked as a rough general proxy. Actual transportation costs for any given generator will vary.

Beyond the transportation cost an additional 1.25% price adder is included. The adder represents gas used for compression which is needed to move gas along the pipeline. Like the $0.40/MMBtu transportation cost, this is a general approximation.

Detailed Gas Prices for the Ninth Plan

A workbook with more details and values for the gas price forecast is available on the Ninth Power Plan webpage.[9]

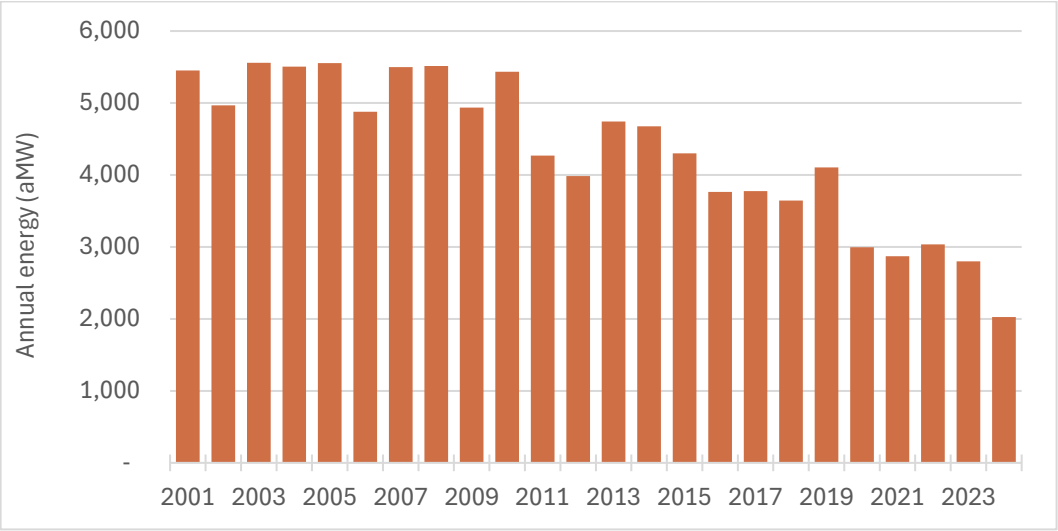
Renewable Natural Gas

Council staff did not create a renewable natural gas forecast for the Ninth Power Plan. This is due to the assumption that renewable natural gas is more highly valued by local distribution companies for decarbonization as compared to the electric power industry. This assumption is based on similar assumptions found in the integrated resource plans of dual-fuel utilities in the Northwest.[10]

Coal in the Northwest Power System

The role of coal generation in the Northwest power system has declined over the past two decades and is expected to further decline going forward. The figure below shows the decreasing use of coal in the Northwest power system on an annual average energy basis.

Figure E - 6: Coal Generation in the Northwest, 2001-2024



The reduction in coal generation is due to multiple factors, with coal retirements playing a role. The Northwest has seen four large coal unit retirements in recent years: Boardman, Centralia Unit 1, and Colstrip Units 1 and 2 (there have been smaller unit retirements as well). In recent years, other coal units have converted to gas or made plans to convert to gas. These conversions are two units at Jim

[9] For the detailed analysis of gas prices, see: https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.
[10] Please see page E.14 in the appendix of Puget Sound Energy's 2023 Gas Utility Integrated Resource Plan and page 6-20 of Avista's 2023 Electric IRP

Bridger (already done), a planned conversion at Centralia Unit 2, and planned conversions at North Valmy units 1 and 2.[11] Please see Technical Appendix B – Existing System and Polices for more discussion on coal retirements and conversions.

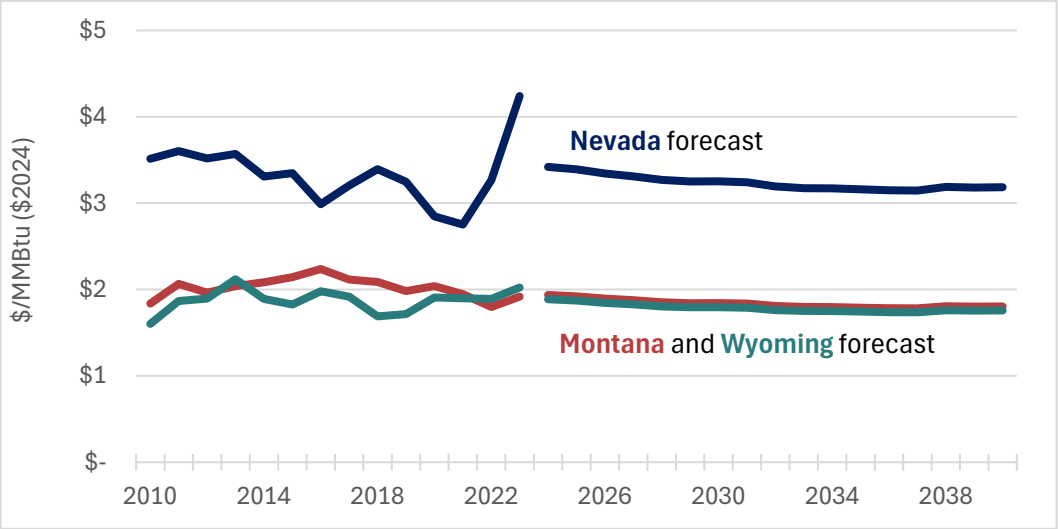
Coal Price Forecast

The Council's coal price forecast is based on EIA forecasts and data. The forecast steps are below:

1. The national EIA Annual Energy Outlook coal forecast sets the general forecast trend (the 2023 forecast was used since the EIA did not publish a 2024 Annual Energy Outlook)
2. The EIA forecast is scaled to state level forecasts using three-year average historical commodity prices for electric power sector delivered coal
3. The forecast is brought to the Fuel Advisory Committee for review
4. The forecast is brought to the Council Members for review

The final forecast for coal price in the Ninth Power Plan is shown in Figure E - 7below. Prices are relatively stable to slightly declining in real dollar terms over the forecast period. This is due to the underlying EIA forecast that exhibits the same behavior.

Figure E - 7: Ninth Plan Coal Price Forecast



[11] https://www.idahopower.com/energy-environment/energy/energy-sources/our-path-away-from-coal.

Detailed Coal Prices for the Ninth Plan

A workbook with more details and values for the coal price forecast is available online on the Ninth Power Plan webpage.[12]

Fuel Oil in the Northwest Power System and Price Forecast

Fuel oil is rarely used in the Northwest, comprising under 0.1% of 2024 annual energy generated in the region. The forecast for the Ninth Power Plan is based on EIA forecasts and data. The forecast steps are below:

1. Historical distillate fuel oil prices at the state level are collected, the state prices are averaged into one Northwest price
2. The EIA 2023 Annuel Energy Outlook forecast is used to inform the general price trend of future prices
3. The EIA forecast is relatively flat, for simplicity the Ninth Plan forecast is pegged at the 2025 forecast value (this value is closest to the midpoint of the EIA forecast range from the 2023 AEO)
4. Discuss final forecast with Fuels Advisory Committee
5. Discuss forecast with the Council for review

The fuel oil price forecast for the Ninth Plan is $20.88/MMBtu. Biofuels, which appear late in the plan (starting in 2045), are assumed to have the same price based on current price trends (in 2025 biofuels, like bio or renewable diesel, are similarly priced to distillate fuel oil).[13, 14]

Nuclear Power in the Northwest Power System & Fuel Forecast

The Northwest has one nuclear reactor, the Columbia Generating Station (CGS). It generates around 1,100 aMW of energy per year, slightly less during refueling years (which occur on odd-numbered years). For the Ninth Power Plan, the Council did not create a standalone nuclear fuel price forecast.

[12] For details on the coal price forecast, see: https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.
[13] Average renewable diesel and diesel prices in California: https://afdc.energy.gov/data/10969.
[14] More information can be found in the final two slides of this presentation: https://nwcouncil.app.box.com/s/ctds6n6jmvfq7ybckmzzy8mwuubh8jp9.

Rather, the cost of fueling CGS is imbedded into the resource operating costs. The embedded costs are the same as were used in the 2021 Power Plan.

Fuel Related Emissions

Existing System Emissions

Please see the Technical Appendix B – Existing System and Polices, for discussion on emissions from generation.

Upstream Methane Emissions

The 2021 Power Plan included estimates for upstream emissions associated with natural gas and coal. In the 2021 Plan, this increased CO_2e emissions from the combustion of a MMBtu of gas from 118 lbs. to 136 lbs., and for coal from 216 lbs. to 219 lbs.[15]

While upstream emissions related to natural gas and coal still exist, for the Ninth Power Plan, upstream emissions are not included. This is due to three reasons:

- Symmetry issues: many resources that could be picked in the Ninth Plan arguably have upstream emissions and/or other environmental externalities.
- Residual emissions issues: Rules in the US (via the EPA), BC (via the BCER), and Alberta (via the Alberta Energy Regulator) are addressing upstream methane emissions going forward (US rule estimated to reduce upstream emissions ~80% compared to BAU).[16] Once regulated, the Council typically views the cost of regulatory compliance as imbedded and any additional emissions as residual.[17] Please see Technical Appendix C - Environmental Methodology for more discussion on residual emissions.
- Treatment of existing vs. new resource: the Council's environmental methodology is focused on new resources, but this value has a large impact on existing resources.

[15] Details on these values are available here: https://www.nwcouncil.org/2021powerplan_upstream-methane-emissions.
[16] https://www.epa.gov/newsreleases/biden-harris-administration-finalizes-standards-slash-methane-pollution-combat-climate#:~:text=EPA's%20final%20rule%20leverages%20the,the%20impacts%20of%20this%20rulemaking.

Technical Appendix F: Electricity Demand Forecast

Contents

Introduction 2
Forecast Framework 3
Forecast Zones 4
Forecast Futures 6
Load Data (Historical) 7
Weather 9
  Historical 9
  Future Patterns 10
Economic Input Data 13
  Low Economic Growth Case 14
Residential Sector 14
  Housing Stock 15
  Residential End Use 17
  High Building Electrification in the Residential Sector 23
Commercial Sector 24
  Building Stock 25
  Commercial End-Use 27
  High Building Electrification in the Commercial Sector 29
Industrial Sector 30
Data Center Forecast Input 31
Electric Vehicles 33
  Input Electric Vehicle Demand 34
  Electric Vehicle Charging Profiles 37
Rooftop Solar 38
  Rooftop Solar Installations in the Northwest 39
  Rooftop Solar Shapes and Generation 41

Hydrogen Load Forecast 42
Energy Shaping 44
Forecast Results 45
Energy 48
Peaks 52
Sales Forecast 55

Introduction

The electricity demand forecast is a power plan requirement. Per the Northwest Power Act, as part of its regional power plan, the Council is required to develop and include "a demand forecast of at least twenty years....".[1] The forecast doubles as both a key and early input to the planning process, as well as a final plan output. Therefore, two distinct forecast cycles are performed, separated in time, and with unique purposes. The first cycle occurs at the beginning of the power planning process and produces the *frozen-efficiency* forecast. The purpose of this forecast is to create an actionable set of demand inputs for the downstream power planning models and tools. The term *frozen-efficiency* means that the forecast does not assume new potential for demand side resources. Rather, the potential for those resources is captured in the energy efficiency, demand response, and behind-the-meter solar supply curves to provide resource options for the power planning models to consider alongside supply side options.[2] The second forecast cycle occurs at the end of the planning process when the selected demand side resources from the plan are factored into the demand forecast. This is known as the *sales forecast*.

Exactly how the future of electricity demand unfolds is uncertain. Therefore, the electricity demand forecast refers to a set of future outcomes that forms a range of potential demand. It is considered a long-term forecast since it projects demand out twenty years. It's more than just a glimpse of a far-off future; it also provides insights into the near term (one to three years) and mid-term demand for electricity. In fact, the forecast futures are developed specifically around the acknowledgement of near, mid, and long-term demand uncertainty.

The demand forecast is locational - each of the 13 balancing authorities that operate in the Northwest are represented. In addition, an overall system-wide energy and peak forecast is also produced. For time-scale, the forecast is divided into hourly, monthly and annual demand segments. Forecasting is done on the sector level - residential, commercial and industrial - and for other special classes such as electric vehicles, data centers, and rooftop solar.

[1] Northwest Power Act, Section 4(e)(3)(F).
[2] Technical Appendices H, I, and J cover the development of potential supply curves for conservation, demand response, and rooftop solar, respectively.

Table F - 1: Demand Forecast Overview

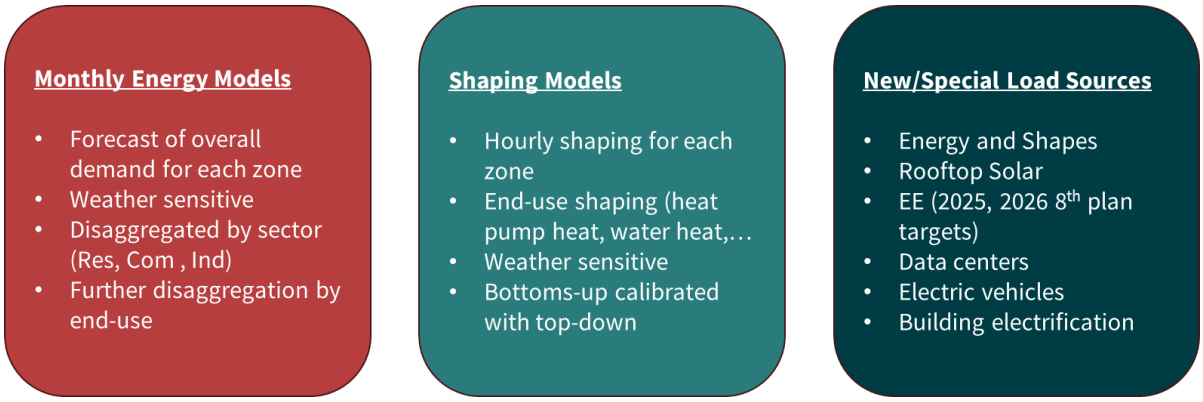
Forecast horizon	2025 – 2046
Geographic unit locations	13 balancing authorities (referred to as Zones) and the entire Northwest region (System)
Future weather	3 climate model patterns 1 typical year pattern that reflects historical normals 26 weather stations
Forecast Pathways	5 unique pathways formed by combining input data sets which capture uncertainty and variability
Demand futures	20 5 pathways across 4 weather patterns
Forecast output time-scale	Annual, monthly, daily, hourly
Sectors	Residential, Commercial, Industrial
Other Classes	Data Centers, Electric Vehicles, Rooftop Solar, Energy Efficiency
Structure	A set of integrated models which incorporate end-use concepts into an econometric modeling framework

Forecast Framework

To develop the Ninth Plan Forecast, the Council enlisted Itron[3] to help us develop a new forecasting framework. The framework may be thought of as a set of integrated models. Individual energy regression models that create a forecast of monthly energy demand are integrated with electricity end-use, and zonal energy shaping models to produce daily and hourly energy demand.

[3] https://na.itron.com/en/categories/energy-forecasting.

Figure F - 1: Forecast Framework



The monthly energy models are built out for each of the 13 balancing authorities, which are considered the 13 forecast zones for the demand forecast. These are individual regression models built up from historical data sets that cover the years 2010 through 2024. The zonal regression models are primarily a function of variables that cover heating demand, cooling demand, and all other demand, as shown in Figure F - 2

$$Demand(Zone,\ Month) = f(XHeat,\ XCool,\ XOther,\ other)$$

Figure F - 2: Monthly Energy Forecast Variables

XHeat Variable
- Res and Com sectors
- Building stock
- Saturation of electric heating related end-uses (like heat pumps, resistance heating,…)
- Efficiency of end-uses
- Economic factors like income, employment,…
- Weather – Zonal specific HDD splines

XCool Variable
- Res and Com sectors
- Building stock
- Saturation of electric cooling related end-uses (heat pumps, central AC,…)
- Efficiency of end-uses
- Economic factors like income, employment,…
- Weather – Zonal specific CDD splines

XOther Variable
- Res and Com sectors
- Building stock
- Saturation of non heating or cooling end-uses (electric water heating, electric cooking, …)
- Efficiency of end-uses
- Economic factors like income, employment,…

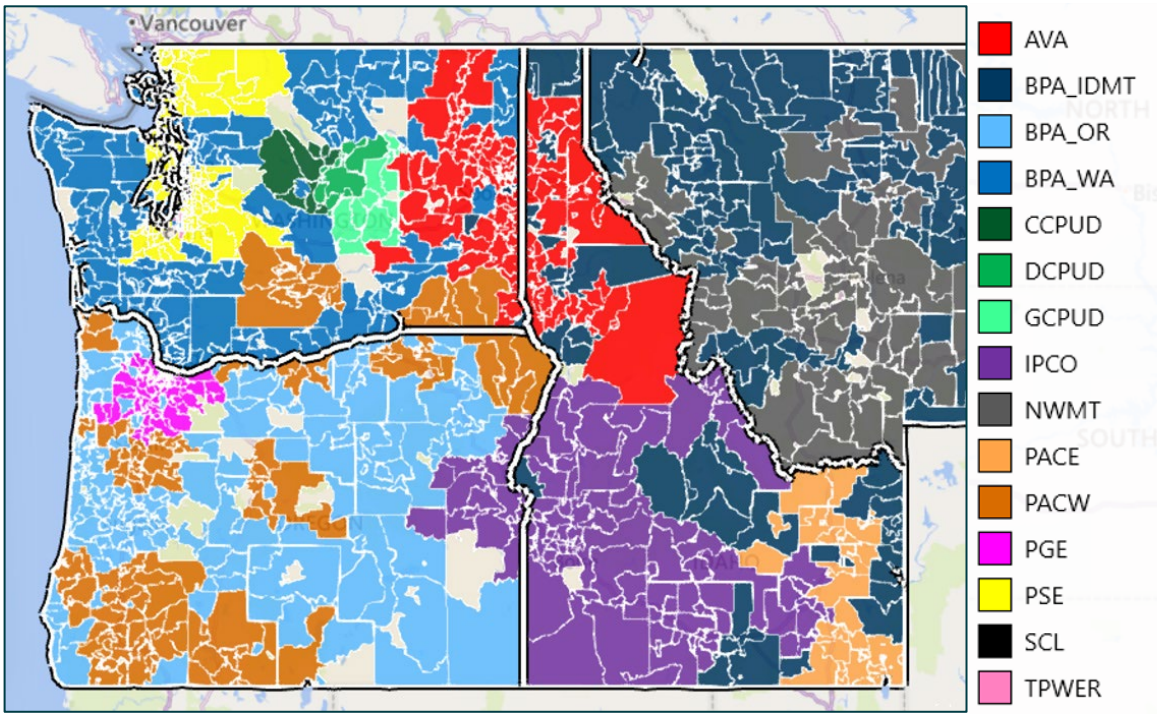
Forecast Zones

The forecast framework was set up to create 13 individual forecasts in the region, in addition to an overall system or regional forecast. The forecast zones and their associated abbreviations are in Table F - 2.

Table F - 2: Forecast Zones

Acronym	Name	Acronym	Name
AVA	Avista	PACE	PacifiCorp East
BPA	Bonneville Power Administration	PACW	PacifiCorp West
CHPD	Chelan County	PGE	Portland General
DOPD	Douglas County	PSE	Puget Sound
GCPD	Grant County	SCL	Seattle City Light
IPCO	Idaho Power	TPWR	Tacoma Power
NWMT	Northwestern		

Figure F - 3: Forecast Zone Map[4]



[4] In the figure, the Bonneville zone is broken out into individual states; however, in the forecast there is only one Bonneville zone.

Forecast Futures

There is uncertainty as to how the future demand for electricity might unfold over the next twenty years. Accordingly, one of the objectives of the forecast was to create an informative spread of potential demand futures, focusing on four primary sources of demand and planning uncertainty.

1. Future weather – some demand sectors such as residential and commercial are highly temperature sensitive
2. Magnitude – mid, higher, and lower trajectories the magnitude of the overall future demand are included to reflect uncertainty
3. Timing of growth - accounting for variance in early, mid, or late in the planning horizon
4. Shape of future demand – reflecting differences in seasonal, flat, or peaky demand requirements

Table F - 3 and Table F - 4 provide an overview of how the 20-year forecast futures were developed by combining a set of forecast model inputs that define specific demand pathways with variations on future weather patterns.

Table F - 3: Pathway Input Components

Model Input Set	Trajectory	Magnitude	Timing	Location	Shape
Economic Forecast	Higher and lower economic growth forecasts	Moderate, sector-wide	Throughout	Throughout	Lifts or lowers demand floor and ceiling
Data Centers	Mid, low and high growth	Significant – very large single loads	Early	Heavy in data center friendly zones	Relatively flat
Electric Vehicles	Higher and lower growth in vehicles	Moderate on residential and commercial sector	Mid to Late	Zones with large urban areas especially	Very peaky
Building Electrification	Higher and lower	Moderate on residential and commercial	Late	Zones within the states of Oregon and Washington	Seasonal, especially winter, and very peaky
Hydrogen Production	Higher and lower	Moderate, single-large load type	Late	Heavier in potential hydrogen zones	Relatively flat, added post-processing

Table F - 4: Pathway Design

#	Description	Economic Growth	Data Center	Transportation	Building Electrification	Hydrogen Production
P1	**High Growth**	Higher	High	Higher	Higher	Higher
P2	**Low Growth**	Lower	Low	Lower	Lower	Lower
P3	**Early Growth**	Higher	High	Lower	Lower	Lower
P4	**Late Growth**	Higher	Medium	Higher	Higher	Higher
P5	**Mixed Bag**	Higher	Medium	Higher	Lower	Higher

The use of the term *higher* does not necessarily mean it is judged as an especially high case. Similarly with the term *lower*. It is meant to indicate that two potential trajectories were tested, with one being higher than the other.

Combining the five pathways (P1, P2, P3, P4, P5) with each of the four future weather patterns (discussed more below) culminates in twenty demand forecast futures.

Load Data (Historical)

The forecast model relies on historical load data by balancing authority. A complete hourly, daily, and monthly set spanning the years of 2008 through 2024 for each balancing authority was compiled for the forecast.

The historical data was sourced from the EIA Hourly Electric Grid Monitor tool[5]. A few things to note:

1. Data scrubbing was performed to repair occasionally erroneous reported hourly load data.
2. The hourly load data for the balancing authorities PACE and NWMT was modified and reduced to reflect the portion of the load that is in region.
    a. PACE: the in-region load (E. Idaho) portion was estimated to be roughly 10% of the overall PACE Balancing Authority load
    b. NWMT: the in-region load (W. Montana) portion was estimated to be roughly 31% of the overall NWMT Balancing Authority load.

[5] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

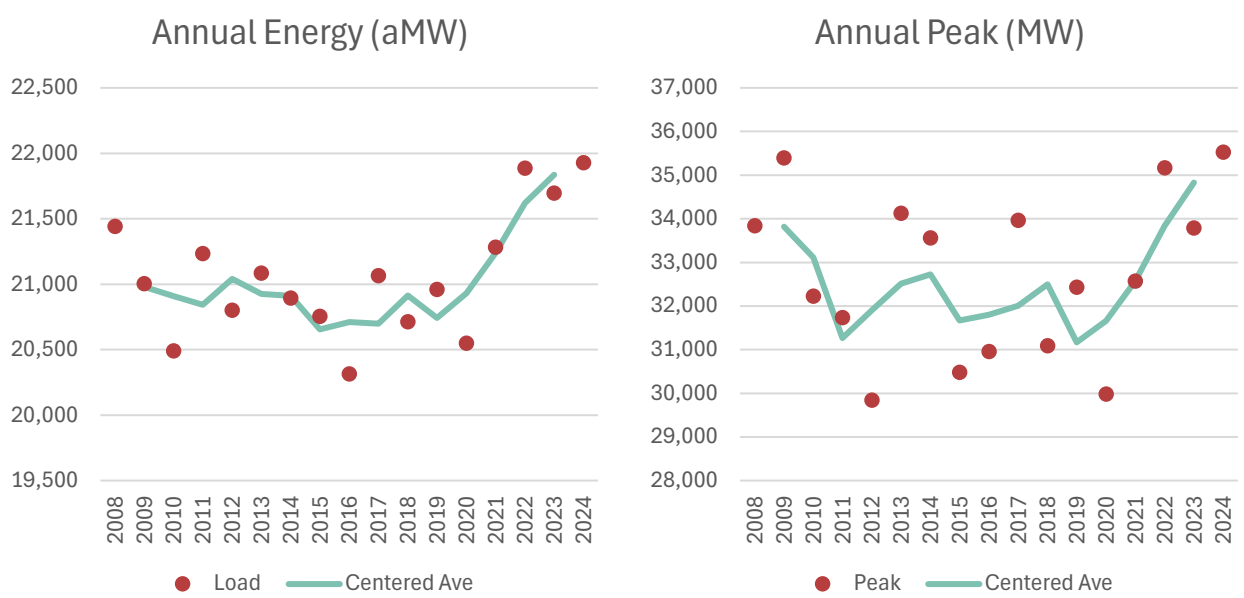
The zones vary in terms of geographic size, weather, and demand for electricity. Overall system-wide demand historically peaks in the winter season. However, some zones are summer peaking, and others alternate between seasons.

Table F - 5: Load Characteristics by Zone

Zone	Percent of Region Load	Peak Season	Zone	Percent of Region Load	Peak Season
Region	100	Winter	SCL	5	Winter
BPA	30	Winter	GCPD	3	Summer
PSE	13	Winter	TPWR	3	Winter
PGE	12	Mix, but lately summer	PACE	3	Summer
PACW	11	Mix	NWMT	2	Mix
IPCO	10	Summer	DOPD	1	Winter
AVA	7	Mix	CHOD	1	Winter

Generally, the demand for electricity has been rising in the region since 2020 for both annual energy and peak.

Figure F - 4: Region-wide Annual Demand for Electricity



Weather

Weather is a key driver of electricity demand. The demand for space and water heating in the winter, and cooling in the summer can fluctuate significantly based on temperatures. The relationship between actual, historical weather, and demand must first be understood and modeled. Then, a future weather pattern is required to forecast demand across the planning horizon.

Historical

Historical hourly weather data, primarily dry-bulb temperature, was collected and compiled for 26 weather stations across the region. The raw weather data sets were acquired from AccuWeather.[6]

The weather station temperature data was compiled into heating degree day (HDD) and cooling degree day (CDD) values across multiple temperature cut-points. Heating degree days are a measure of how cold the temperature was for a single day, or period of days. As an example, for a winter day with an average temperature of 20 degrees F, the HDD value for a cut-point of 55 degrees is calculated as 55 – 20 = 35 HDD_{55}. Analogous to the HDD metric, cooling degree days are a measure of how warm a day or period of days were. Suppose the average temperature for a summer day was 80 degrees F. With a CDD cut-point of 70 degrees, the CDD value is 80 – 70 = 10 CDD_{70}. The HDD cut-points are set at 5-degree increments from 35 degrees to 70 degrees F. The CDD cut-points are also set at 5-degree increments from 85 degrees to 55 degrees F.

For the forecast zones that contain more than one weather station, the station values are weighted based on load proportions.

Table F - 6: Weather Stations

Station	Location	Zone	Station	Location	Zone	Station	Location	Zone
KBFI	Seattle-Boeing, WA	PSE, SCL	KGTF	Great Falls, MT	NWMT	KPIH	Pocatello, ID	IPCO, PACE
KBIL	Billings, MT	NWMT	KHIO	Hillsboro, OR	PGE	KRNT	Renton, WA	PSE
KBLI	Bellingham, WA	PSE	KHRI	Hermiston, OR	BPA	KSEA	Seattle-Tacoma, WA	SCL
KBOI	Boise, ID	IPCO	KMFR	Medford, OR	PACW	KSFF	Coeur d'Alene, ID	AVA
KEAT	Wenatchee, WA	CHPD, DOPD	KMSO	Missoula, MT	NWMT	KSLE	Salem, OR	PACW, PGE

[6] https://www.accuweather.com.

Station	Location	Zone	Station	Location	Zone	Station	Location	Zone
KEPH	Ephrata, WA	GCPD	KMWH	Moses Lake, WA	GCPD	KTIW	Tacoma, WA	TPWR
KEUG	Eugene, OR	BPA	KOMK	Omak, WA	BPA	KTWF	Twin Falls, ID	IPCO
KGEG	Spokane, WA	AVA	KPAE	Everett, WA	BPA	KYKM	Yakima, WA	PACW
KGPI	Glacier Park, MT	BPA, NWMT	KPDX	Portland, OR	PACW, PGE			

Future Patterns

The historical weather and load data for each zone is used to create a model of how demand responds to weather. To forecast future demand, a future weather pattern is necessary. To reflect the uncertainty of future weather, four patterns were developed for the Ninth Plan demand forecast. One normalized weather pattern, called Typical Meteorological Year (TMY), and three unique climate model patterns (Climate A, C, G).[7]

TMY Weather

While the bulk of the Ninth Power Plan analysis assumes climate model informed weather, the Council also creates a load forecast based on TMY weather. This is used to produce a weather-normalized load outlook, which can help to isolate the impact of structural and economic changes over time. To build the 20-year future TMY pattern, a historical 20-year record of weather from 2003-2022 was used to calculate average HDD and CDD values for each month for each station and zone. Next, daily weather shapes from select historical months were used to create a realistic, single annual weather pattern calibrated to monthly 20-year averages. The pattern is then repeated each year – this defines the TMY weather pattern.

Climate Scenario Weather

Three future weather patterns were derived from climate scenario data provided by the River Management Joint Operating Committee (RMJOC). Technical Appendix D – Climate Model Data and Assumptions provides more detail on the climate model data used in the Ninth Plan.

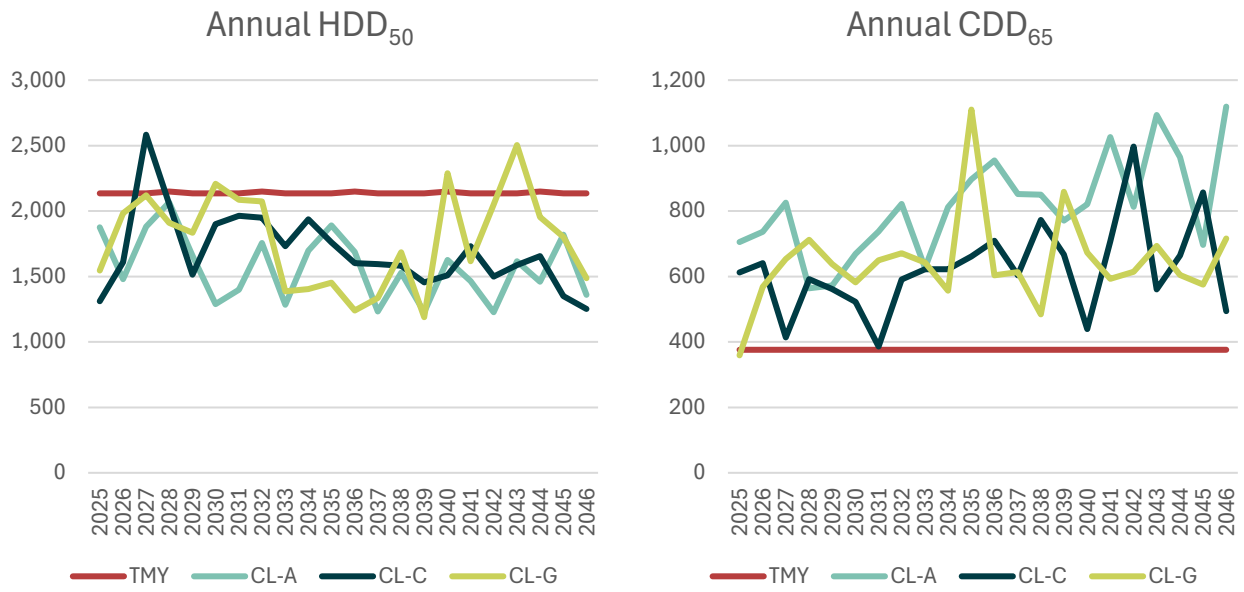
Unlike the TMY weather pattern, the climate scenario pattern temperatures each vary from year to year. For example, in Climate Scenario A pattern, some summers are warmer than others, and some winters are cooler than others.

[7] See Technical Appendix D – Climate Model Data and Assumptions for more information on the Council's selection of these climate models and the temperature trends in the data.

In most years, the climate scenario weather patterns exhibit warmer winter and summer temperatures than the TMY pattern (20-year normal). Though these climate scenario patterns are generally warmer than the 20-year norm, they do exhibit extremes in terms of cold winter temperatures.

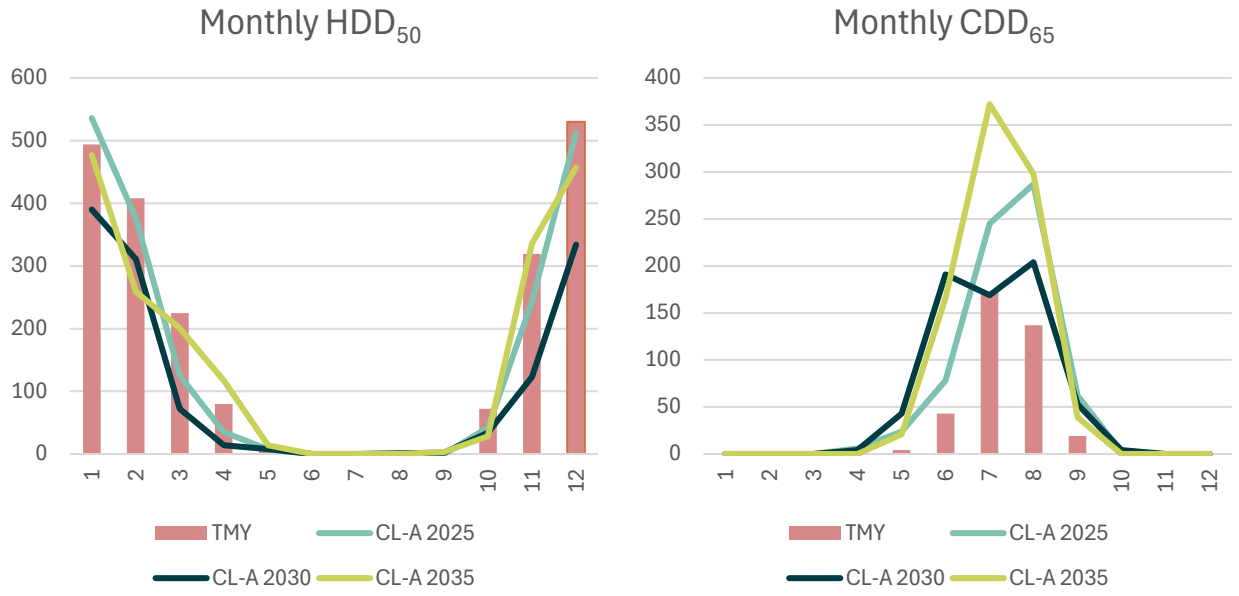
To illustrate, HDDs and CDDs with select cut-points are graphed below. Figure F - 5 shows the sum of HDD_{50} and CDD_{65} on an annual basis by planning year. Remember, the lower the sum of the HDDs the warmer the winter is, and the higher the sum of CDDs, the warmer the summer is. These values are for the BPA zone, which covers a wide geographic area of the Northwest and is a winter peaking zone.

Figure F - 5: Sum of Annual HDD_{50} and CDD_{65} for the BPA zone



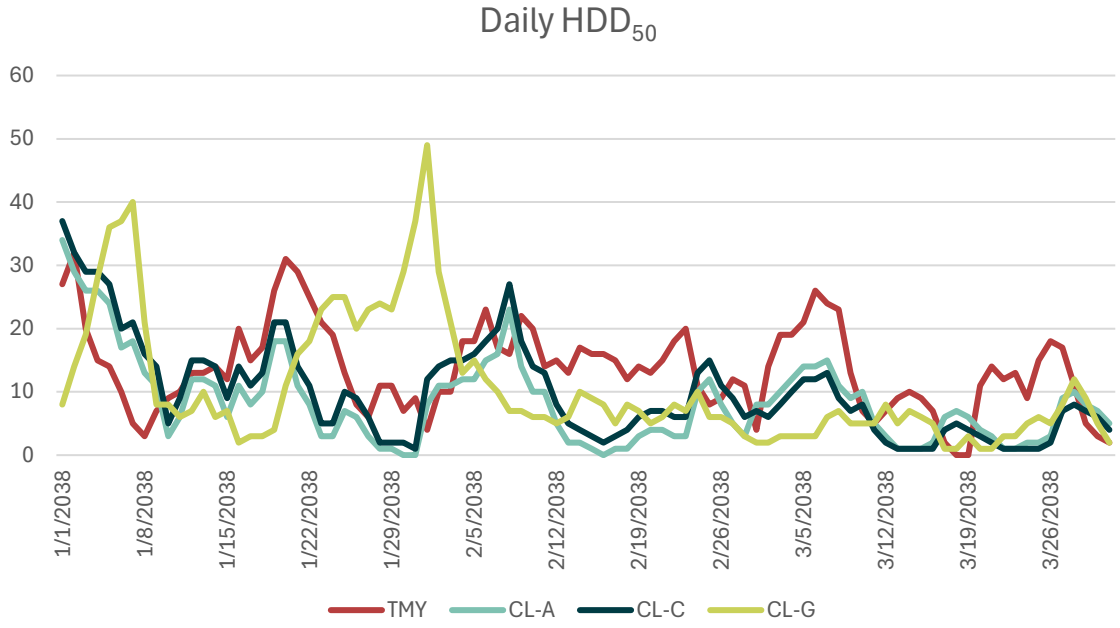
The sum of monthly HDDs and CDDs are shown in Figure F - 6 below for the TMY pattern, and a few select years from the Climate-A weather pattern. As can be seen, the weather pattern for the climate scenario contains substantial year-to-year variability.

Figure F - 6: Sum of Monthly HDD_{50} and CDD_{65} for the BPA zone



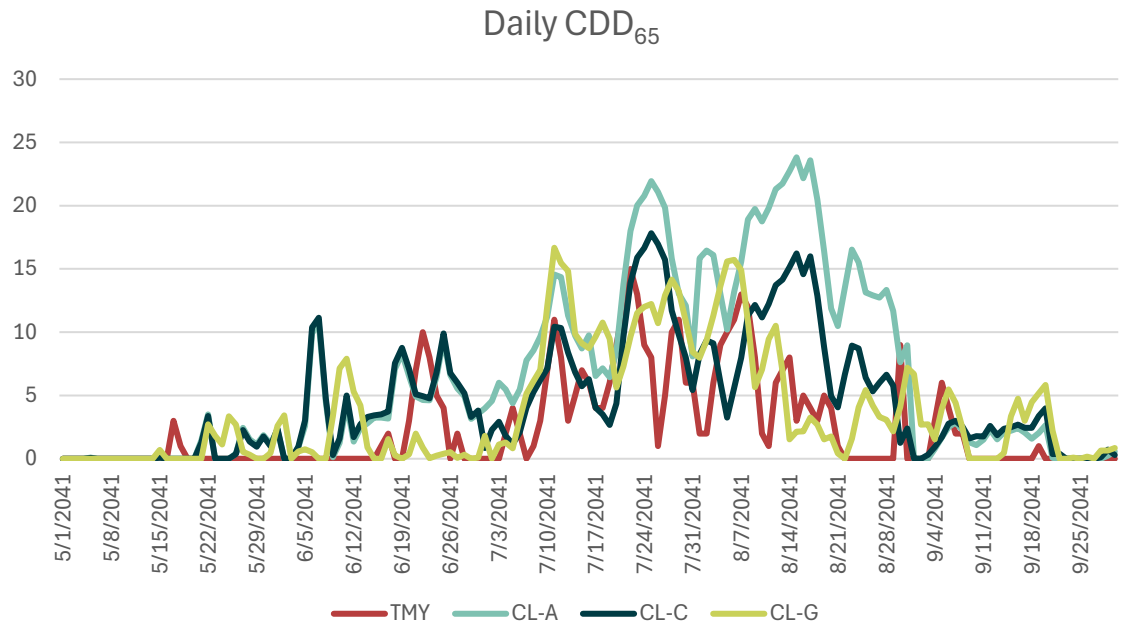
Though generally the climate scenario weather patterns result in milder winters, there are extreme cold events in the future patterns. For example, graphing daily HDD_{50} for the winter of 2038, Climate Scenario G pattern hits a high of 50 HDD_{50}, which means that day hovers around 0 degrees F, even though for the entire winter, Climate Scenario G pattern is warmer than the TMY pattern.

Figure F - 7: Daily HDD_{50} for the BPA zone Winter of 2038



As would be expected, there are extreme heat events in the climate scenario patterns. For example, Figure F - 8 below shows the CDD_{65} values for each day for the summer of 2041. The Climate Scenario A pattern contains some days where the average daily temperature is nearly 90 deg F.

Figure F - 8: Daily CDD_{65} for the BPA zone Summer of 2041



Economic Input Data

Two sets of economic input data were constructed for the forecast model: benchmark and low. The benchmark economic data set was sourced from the S&P Global Market Intelligence Long-Term Annual report from January of 2025. Economic drivers impact the demand forecast for the residential, commercial, and industrial sectors. The key drivers include:

- Population
- Household Size
- Employment
- Gross State Product (GSP)
- Unemployment Rate
- Real Personal Income (RPI)

The economic drivers are available at the state level (ID, MT, OR, WA). These drivers are then allocated to the appropriate forecast zone. For zones that contain multiple states (BPA, PACW), the state level drivers are weighted. The data is used in the forecast model to establish historical

relationships between demand and economic conditions. The forecast of economic conditions then acts as a driver in the forecast models.

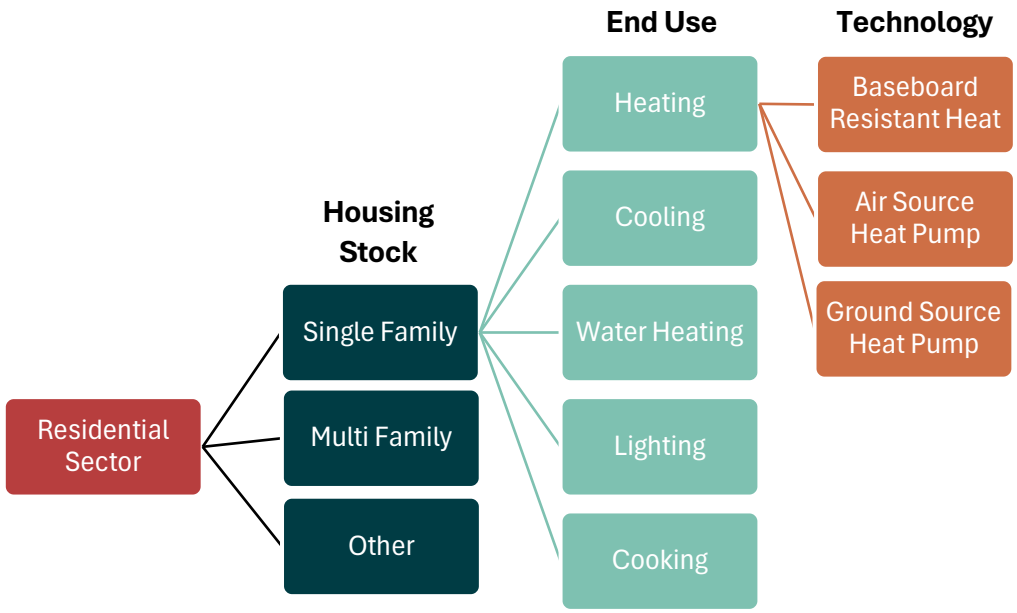
Low Economic Growth Case

A data set with a persistently lower economic growth rate was developed as an input for the Low Growth (Pathway 2) future. For each of the four Northwest states, the growth rates for the economic drivers of population, employment, manufacturing employment, real personal income (RPI), and gross state product (GSP) were reduced on an annual basis throughout the forecast horizon. For example, the annual growth rate for GSP in the state of Washington across the 20-year horizon (2027-2046) was reduced from the benchmark rate of 2.51% to a low rate of 2.19%. The reduced economic growth rates impact demand growth for the residential, commercial, and industrial sectors.

Residential Sector

The residential sector demand is modeled as a function of housing stock, end-use saturation, efficiencies and shapes, economic factors, and weather. At the core of the forecast is a regression model that produces a forecast of monthly energy demand for the residential and commercial sectors. This is the Itron Statistically Adjusted End Use (SAE) approach. Not a traditional end-use model, the SAE approach incorporates end-use information into an econometric modeling framework. A traditional end-use model sums up individual forecasts of demand for each electrical end-use (see Figure F - 9). An econometric model specifies the statistical relationship that is believed to hold between various economic factors and weather to demand.

Figure F - 9: Example of an End-Use Structure



In the SAE regression, there are three model variables: a heating variable, a cooling variable, and a base variable. The heating variable incorporates structural changes in space heating end-use appliance saturation (such as heat pumps) and average stock efficiencies, building shell improvements and economic factors such as personal income, and finally weather related to heating (heating degree days). The cooling variable is similar but focused on space cooling end-uses such as central AC or heat pumps, and weather related to cooling (cooling degree days). The base variable captures the remaining residential non weather-related end-uses, such as lighting, water heat, and cooking.

The model establishes the historical relationship between:

1. Demand
2. Building stock
3. End-use characteristics
4. Weather

The model is then used to forecast future demand as a factor of building stock growth, changes in end-use saturations and efficiencies, and future weather. While the efficiency level for newly installed equipment is held constant, the overall average stock efficiency level may increase over the time horizon as older units turn over.

This section will discuss how the residential sector inputs were developed for the monthly energy model. There are several factors that affect the overall demand for electricity in the residential sector.

Housing Stock

At the base of the residential demand forecast is the existing housing stock and how it might change in the future. The housing stock estimate and forecast is a key baseline dataset for the demand forecast and energy efficiency, rooftop solar, and demand response potential studies. For the Ninth Plan, a housing stock data set was created, covering the years 2010-2050. The data set contains an annual estimate and forecasts of single family, multi-family, and other housing stock for each of the four states (ID, MT, OR, WA). The estimate for Montana is adjusted to represent just the western region of the state.

Single-family is defined as a residential unit with 1 to 4 units, multi-family 5 units or more, and Other is a manufactured or mobile home. The forecast was initially developed for the entire state of Montana and was then scaled down to represent homes west of the Continental Divide (in-region). The percentage of homes in Western Montana was estimated using US Census data by county and results in a 39.7% scaling factor.

An estimate of historical housing stock is necessary for the forecast model to fit to historical demand, and a forecast is needed to project future demand. The process steps follow:

1. The existing housing stock in 2020 was set as a base to work with. This year was selected based on the 2020 US Census.[8]
2. Housing stock estimates for the past were set by moving backward from the 2020 base by estimating the number of housing additions (new) and losses for each year.
3. Similarly, housing stock estimates for the future were set by moving foward from the 2020 base by estimating the number of housing additions (new) and losses for each year.
4. Adds (housing starts) by state were estimated using the S&P Global Market Intelligence August 2024 report.
5. Indivdual housing loss rates by state were estimated using the loss methodology[9] proposed in the US Census.

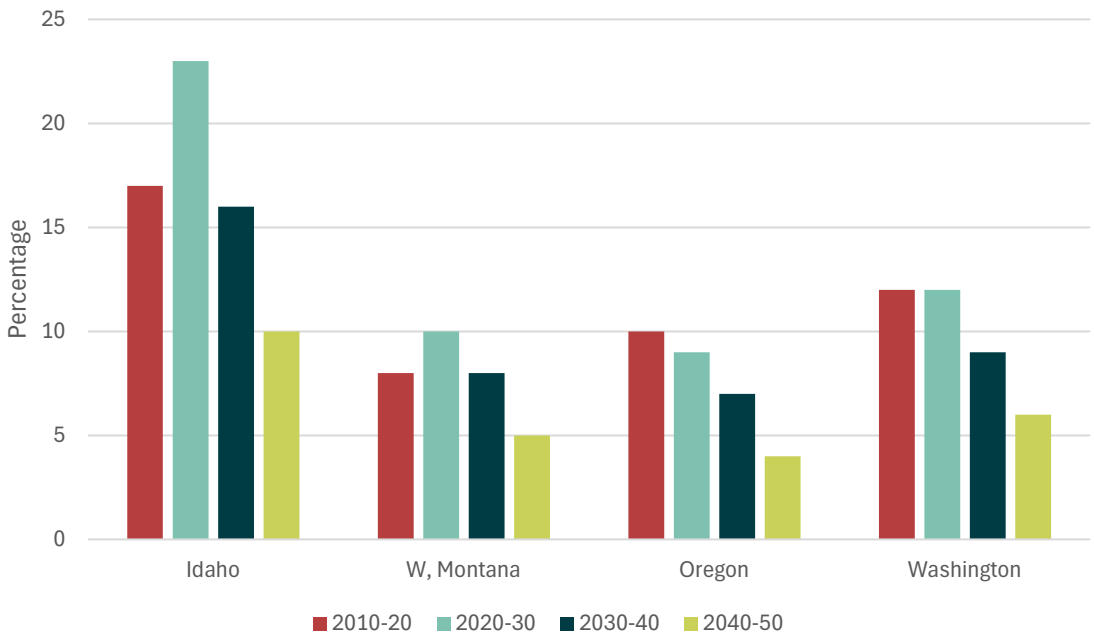
In the region, 53% of the residential units are in Washington. However, in terms of annual growth rate, Idaho is growing the fastest. All four states are seeing a trend towards more multi-family housing. Of the four states, Washington has the highest percentage of multi-family units (23% in 2030), while Idaho has the highest percentage of single-family units (83% in 2030).

Table F - 7: Total Housing Units

Year	Idaho	W. Montana	Oregon	Washington
2020	756,174	220,305	1,819,203	3,213,902
2030	929,824	241,516	1,990,758	3,603,401
2040	1,081,525	259,867	2,130,629	3,930,900
2050	1,191,056	273,127	2,223,413	4,155,420

[8] https://www.census.gov/programs-surveys/decennial-census/decade/2020/2020-census-results.html.
[9] https://www2.census.gov/programs-surveys/popest/technical-documentation/methodology/2020-2023/2023-hu-meth.pdf.

Figure F - 10: 10-Year Housing Unit Growth Rates by State



Residential End Use

The historical and forecast saturations and efficiency levels of residential end-uses are an input variable to the model. Saturation level refers to the percentage of housing units with a specific end-use and technology. Efficiency level is the average of the equipment efficiency for that specific end-use across the entire housing stock, so it is a mixture of both new and older units. The estimated saturations and efficiencies include the effects of codes and standards, but not the savings from future energy efficiency programs.

Twenty residential end-uses are represented in the forecast model.

Table F - 8: Residential End Uses Represented in Forecast

End - Use	Description	Category	Shape Source[10]
EFURN	Electric furnace and resistant room space heaters	Heating	NEEA
HPHEAT	Heat pump space heating	Heating	NEEA
GPHEAT	Ground-source heat pump space heating	Heating	NEEA
SECHT	Secondary heating	Heating	NEEA
CAC	Central air conditioning	Cooling	NEEA

[10] https://neea.org/northwest-end-use-load-research-project.

End - Use	Description	Category	Shape Source[10]
HPCOOL	Heat pump space cooling	Cooling	NEEA
GHPCOOL	Ground-source heat pump space cooling	Cooling	NEEA
RAC	Room air conditioners	Cooling	NEEA
EWHEAT	Electric water heating	Base	NREL ResStock
ECOOK	Electric cooking	Base	NREL ResStock
REF 1,2	Refrigerator, and second Frig.	Base	NREL ResStock
FRZ	Freezer	Base	NREL ResStock
DISH	Dishwasher	Base	NREL ResStock
CWASH	Electric clothes washer	Base	NREL ResStock
EDRY	Electric clothes dryer	Base	NREL ResStock
TV	TV sets	Base	NREL ResStock
FURNFAN	Furnace fans	Heating	NREL ResStock
LIGHT	Lighting	Base	NREL ResStock
MISC	Miscellaneous	Base	NREL ResStock

Saturation and Efficiency Levels

An estimate of historical saturation and efficiency levels are used to calibrate to historical demand. An estimate of the future trajectory of both saturation and efficiency levels is used as an input to the forecast model to project future demand. A stock and flow analysis was performed, by state and end use, to build a data set with historical and future saturation and efficiency estimates.

A number of data sources were used to support the analysis, including the Residential Building Stock Assessments (RBSA)[11] as published by the Northwest Energy Efficiency Alliance (NEEA) from 2011, 2017, and 2022. In addition, data from the Annual Energy Outlook (AEO)[12] from the U.S. Energy Information Administration (EIA) was also used.

The stock and flow analysis is set up to track the annual changes in the end-uses in the housing stock over a period of over 40 years. The data set is initialized in the year 2010 with an estimate of the number of end-use specific units by state and housing type (SF, MF, Other). Information from the 2011 RBSA was used to set the initial conditions, and the model was then calibrated to data from the 2017 and 2022 RBSAs. The stock and flow model then steps through each year calculating the changing saturations and efficiency levels all the way through to the end of the planning horizon 2047. The logic assumes annual loss of specific end-use units due to building demolition and equipment

[11] https://neea.org/residential-building-stock-assessment.
[12] https://www.eia.gov/outlooks/aeo/info_nems_archive.php.

reaching end-of-life. Annual additions of the end-use units are assumed from equipment replacements (due to EOL), new unit installs in existing buildings that did not have that end-use previously, and new construction.

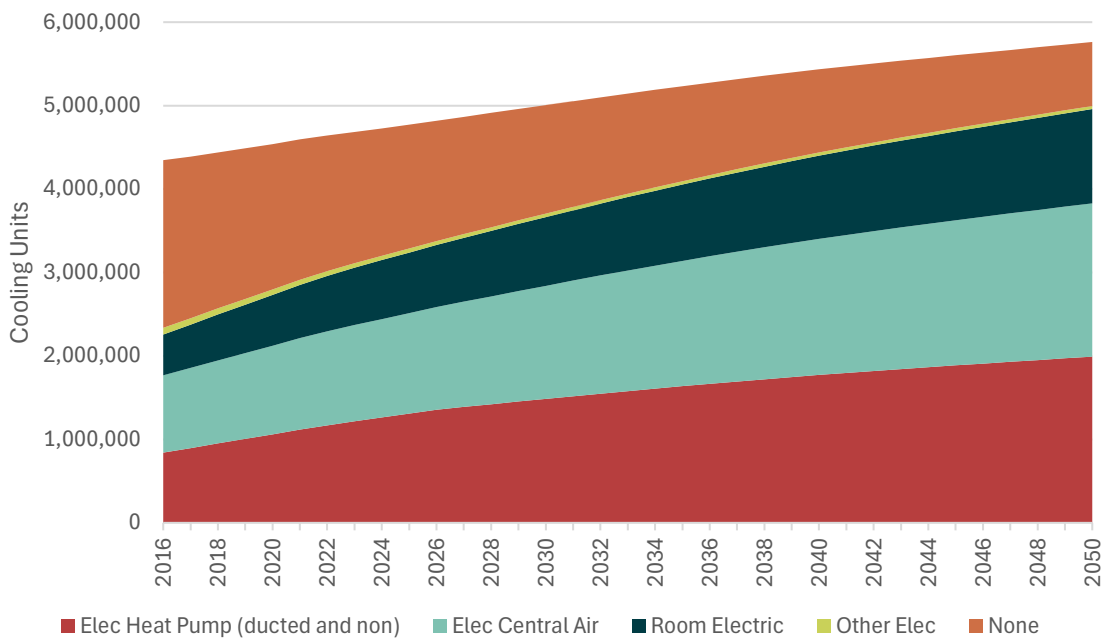
Various efficiency measure units were used, depending on the data available and type of end use, including:

1. HSPF – heating seasonal performance factor
2. COP - coefficient of performance
3. SEER – seasonal energy efficiency ratio

Cooling and Space Heating

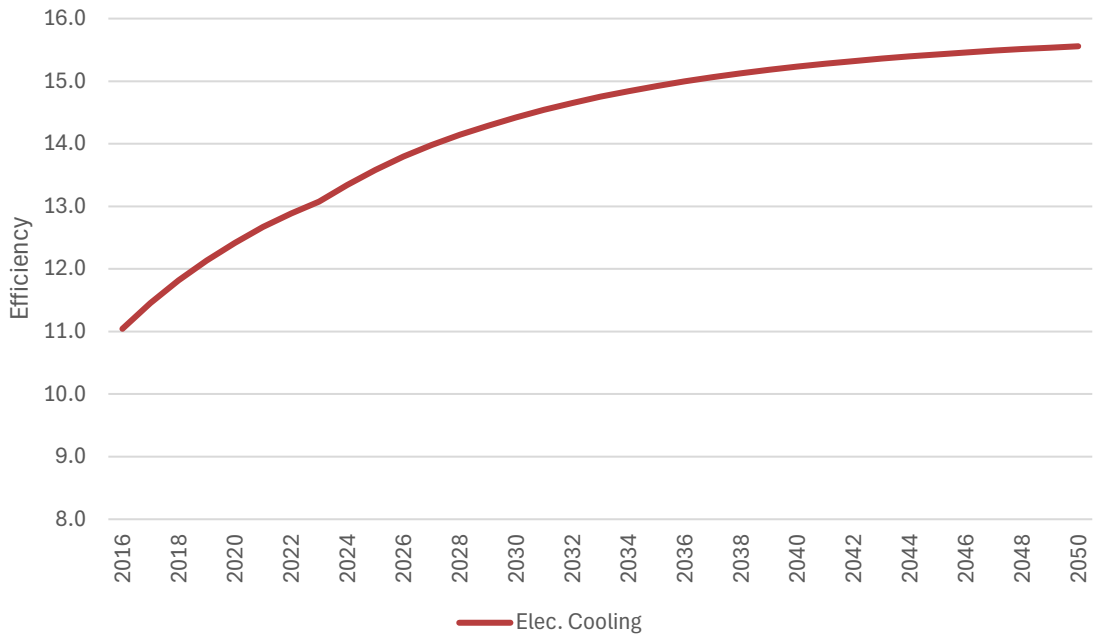
The analysis shows a significant upward trend in cooling installations across the Northwest. For example, for single-family (SF) homes, in 2020 the overall share of housing units with some sort of electric cooling was estimated to be 61.6%. By 2030, it is estimated that 74.1% of SF homes will have some form of electric cooling. For the cooling end-use technology breakdown, roughly 40% of the homes that have electric cooling are expected to have heat pumps, and around 36.5% are expected to use central AC.

Figure F - 11: Number of Cooling Units by Tech - Single Family



With cooling unit stock turnover and new construction, the overall average efficiency for cooling in the residential sector increases over time as new units are added at better efficiencies (frozen from 2027 onward).[13]

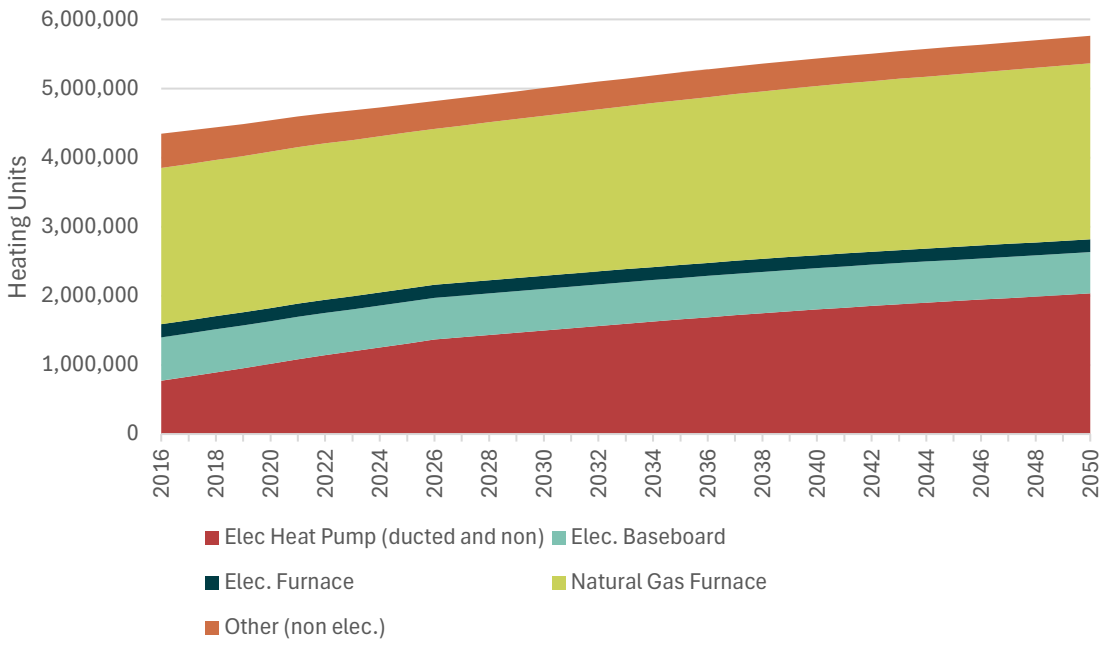
Figure F - 12: Average Unit Efficiency for Cooling (all tech) – Single Family



Heat pump saturations are also trending up for space heating, as might be expected since heat pumps can be used for both heating and cooling. Gas furnaces continue to hold the largest share for single family home heating.

[13] The common practice efficiency levels (also known as "current practice") for new equipment sold today is often more efficient than the average of the existing stock, which includes older, less efficient units, that are no longer available for purchase.

Figure F - 13: Number of Heating Units by Tech - Single Family



As with cooling, due to unit stock turnover and new construction, the overall average efficiency for heating in the residential sector is projected to increase over time as new units are added at better efficiencies (frozen from 2027 onward). Figure F - 14 shows the estimated average efficiency over all space heat pump units in the region.

Figure F - 14: Average Unit Efficiency for Heat Pump Space Heating – Single Family

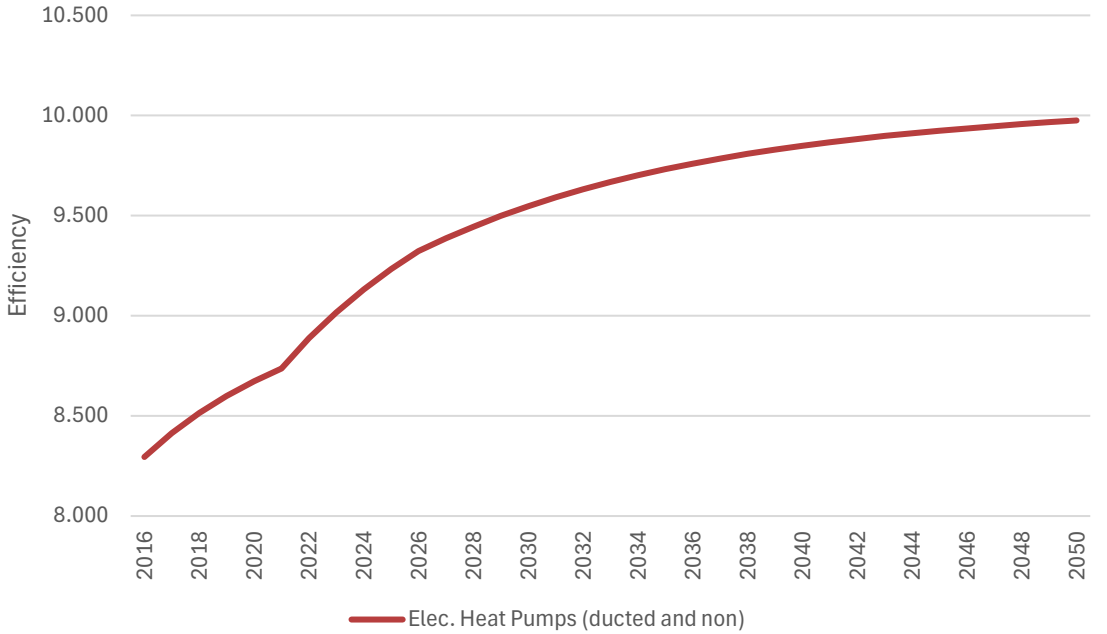
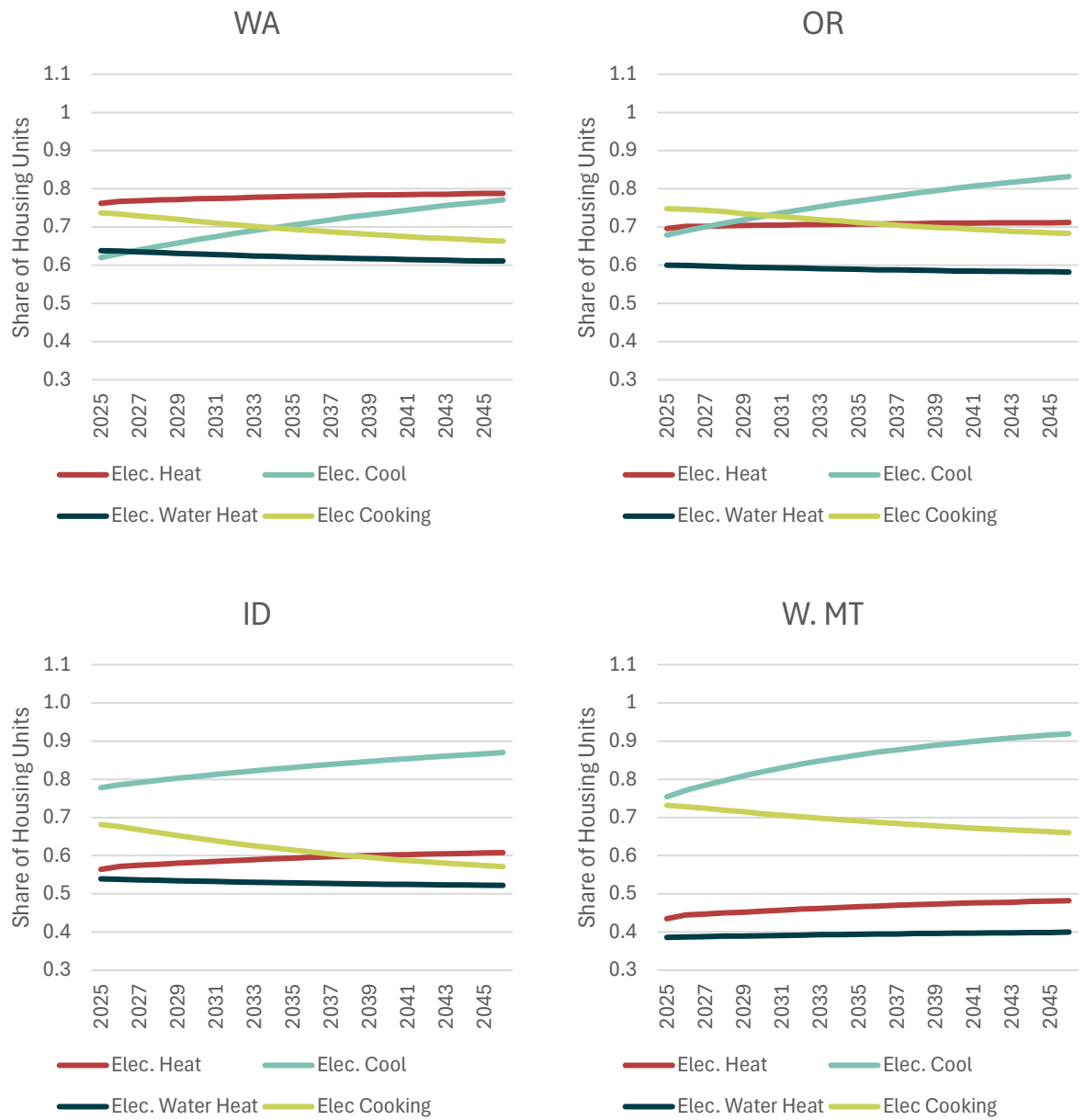


Figure F - 15 summarizes the end-use data by state, across all residential sector building types (SF, MF, Other) and technologies.

Figure F - 15: Residential Sector Saturations by State



End-Use Shapes

The zonal regression models use the end-use saturation and efficiency data to produce an energy forecast. To shape the energy, hourly weather sensitive end-use demand shapes were generated for historical weather and the future weather patterns used in the forecast. These shapes are later

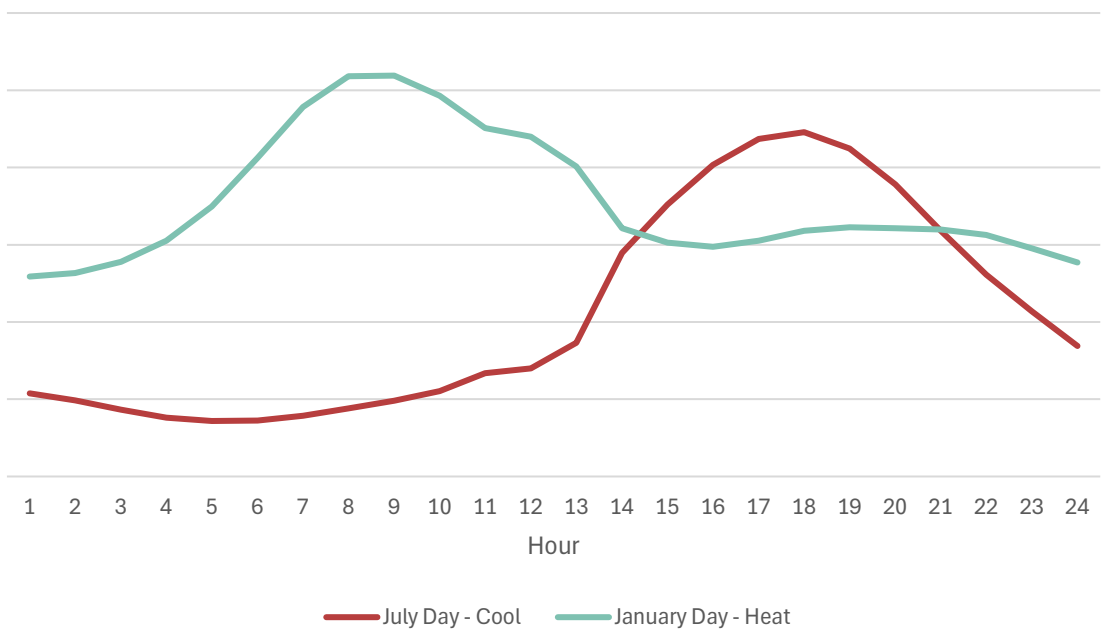
applied to the estimated energy consumption from each end-use and calibrated to each zone's overall demand shape. This is used to create an hourly forecast by sector.

Weather sensitive hourly end-use shapes were derived using information from the NEEA[14] and NREL[15] residential data sets. See

Table F - 8 for the source by end-use.

Figure F - 16 shows example end-use shapes used for modeling heat pump space heating and cooling. The input shapes are derived from average kWh per unit calculations. The heat pump shapes display the peaky aspects of space heating and cooling; a characteristic morning heating ramp in the winter, and a late-afternoon cooling ramp in the summer. These shapes are applied to the forecasted seasonal demand (MWh) from heat pumps through the forecast horizon.

Figure F - 16: Example Heat Pump End-Use Hourly Shape



High Building Electrification in the Residential Sector

The High Growth and Late Growth forecast futures contain a high building electrification input data set. In this input data set, the Council boosted the electric saturations over the base level for space heating, water heating, and cooking. This analysis focused on only zones in Washington and Oregon.

[14] https://neea.org/northwest-end-use-load-research-project.
[15] https://resstock.nrel.gov.

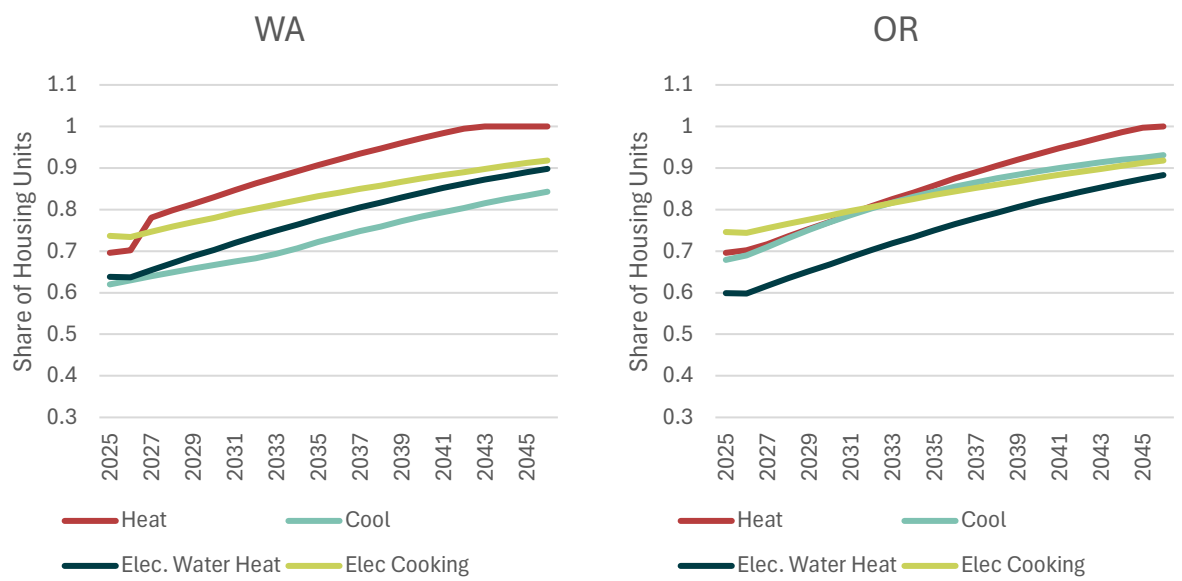
Both states have identified building electrification as an effective way to reduce greenhouse gas emissions in their respective state energy strategies[16,17]. This was accomplished by:

- Setting new building construction to be mostly electric – primarily this is setting space heat to heat pump technologies
- Moving natural gas end-use equipment (such as a gas furnace) to an electric heat pump as the gas unit ages out and needs to be replaced

While building electrification is mostly related to heating use (impacting winter consumption), the modeling does try to capture additional cooling installation as new heat pumps can be used for heating and also cooling in a residence that otherwise might not have had a cooling unit already.

The following figures show the higher saturation rates for electric end-uses by state. Idaho and W. Montana were left the same as the baseline projections.

Figure F - 17: High Electrification Saturations by State



Commercial Sector

Like the residential sector, commercial demand is modeled as a function of building stock (square footage), end-use saturation, efficiency and shapes, economic factors and weather. An input data set was compiled which captures estimates of historical values and a projection of future values for

[16] https://energystrategy.oregon.gov/electrification.
[17] https://www.commerce.wa.gov/energy-policy/state-energy-strategy.

these demand factors. This is an input to the SAE regression model with the three model variables, heating, cooling, and other.

This section discusses how the commercial sector inputs were developed for the monthly SAE energy model.

Building Stock

At the base of the commercial sector demand forecast is an estimate of the existing commercial building stock and how changes might unfold over the course of the planning horizon. For the Ninth Power Plan, a building stock data set was created for the four Northwest states, covering the years 2010-2050. The data set contains estimates of annual commercial floor space (square footage) by state for specific building types. The building types and end-uses align with the US Energy Information Administration (EIA) Annual Energy Outlook (AEO).

Table F - 9: Commercial Sector Building Types and End-Uses

Building Type	End-Uses (for each building type)
Assembly	Space Heating
Education	Cooling
Food Sales	Ventilation
Food Service	Water Heating
Health Care	Cooking
Lodging	Refrigeration
Large Office	Lighting
Small Office	Office
Merchant/Service	Misc
Warehouse	
Other	

Several sources informed the commercial building square foot stock forecast. The Council's 2021 Power Plan[18], NEEA's Commercial Building Stock Assessments[19] (2009, 2014, 2019, and preliminary 2024), and 2023 EIA AEO[20] data.

[18] https://www.nwcouncil.org/2021-northwest-power-plan.
[19] https://neea.org/commercial-building-stock-assessment.
[20] https://www.eia.gov/outlooks/aeo.

Commercial square footage is projected to grow at steady rates, comparable to the past 20 years. In the region, 47% of the commercial buildings floor space is estimated to be in Washington, with Oregon at 37%. All four states are projected to see growth, with the highest growth rates in Idaho and Montana. Figure F - 18, Figure F - 19, and Table F - 10 show the growth in commercial sector across the states.

Figure F - 18: Commercial Building Total Square Footage

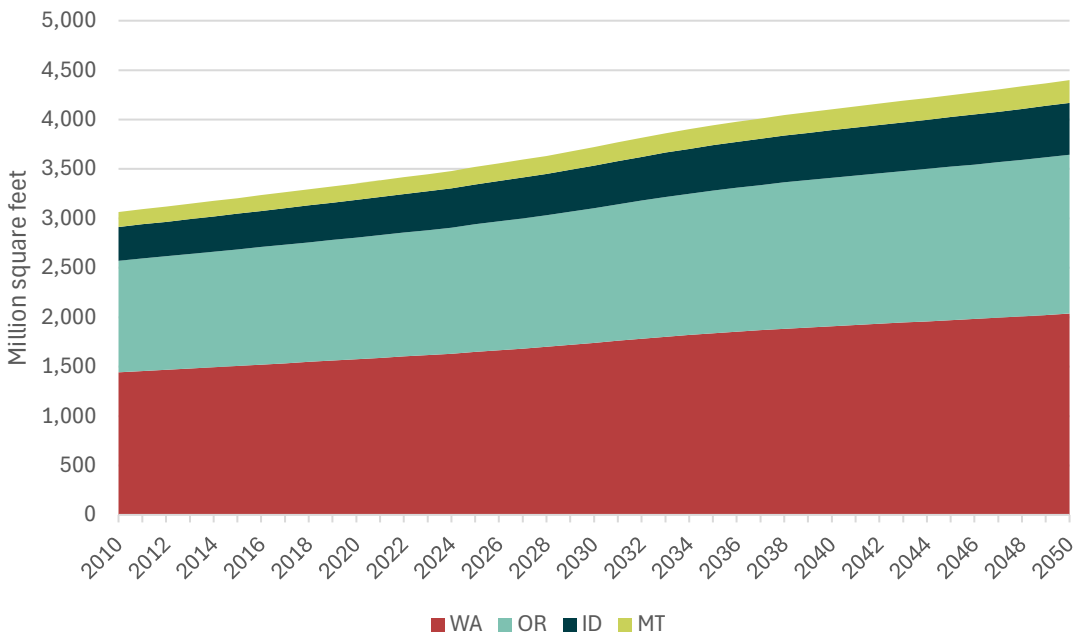


Figure F - 19: Commercial Building Total Square Footage Growth Rate

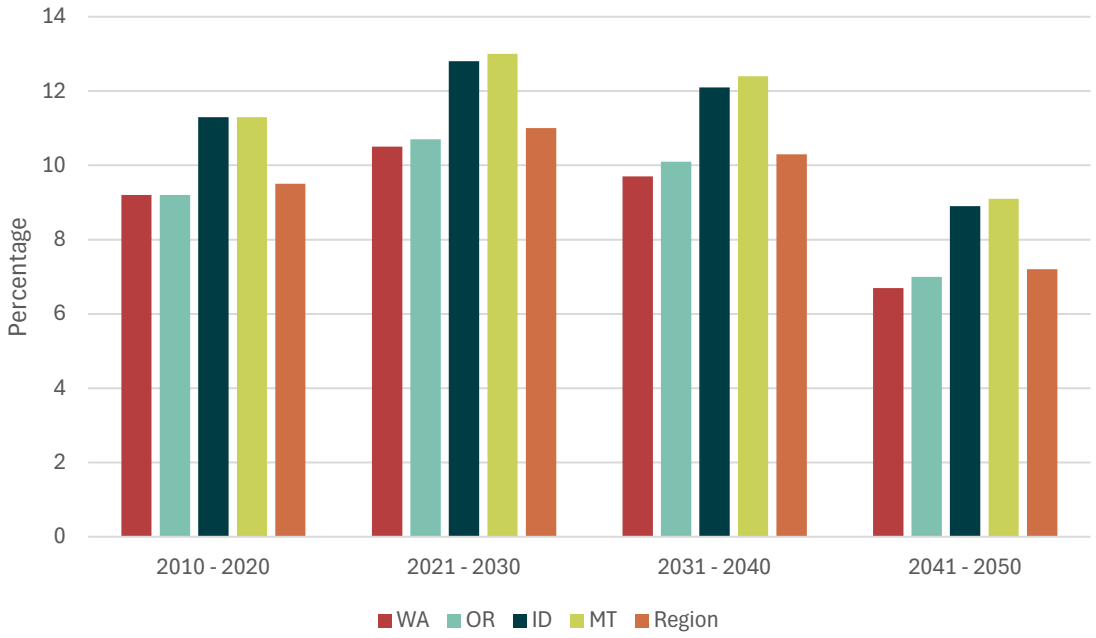


Table F - 10: Total Commercial Floor Space (millions of square feet)

Year	Idaho	W. Montana	Oregon	Washington
2020	381	167	1,231	1,575
2030	430	189	1,363	1,740
2040	481	212	1,501	1,910
2050	524	231	1,607	2,037

Commercial End-Use

As with the residential sector, the historical and forecast end-use saturation and efficiency levels are an input variable to the forecast model. Saturation level refers to the portion of the square footage with a specific end-use, and the efficiency level is the average efficiency level of that end-use across the square footage. The estimates of saturations and efficiency levels are intended to capture codes and standards, but not the estimated savings from future energy efficiency programs, with the efficiency of new equipment frozen at 2027 levels.

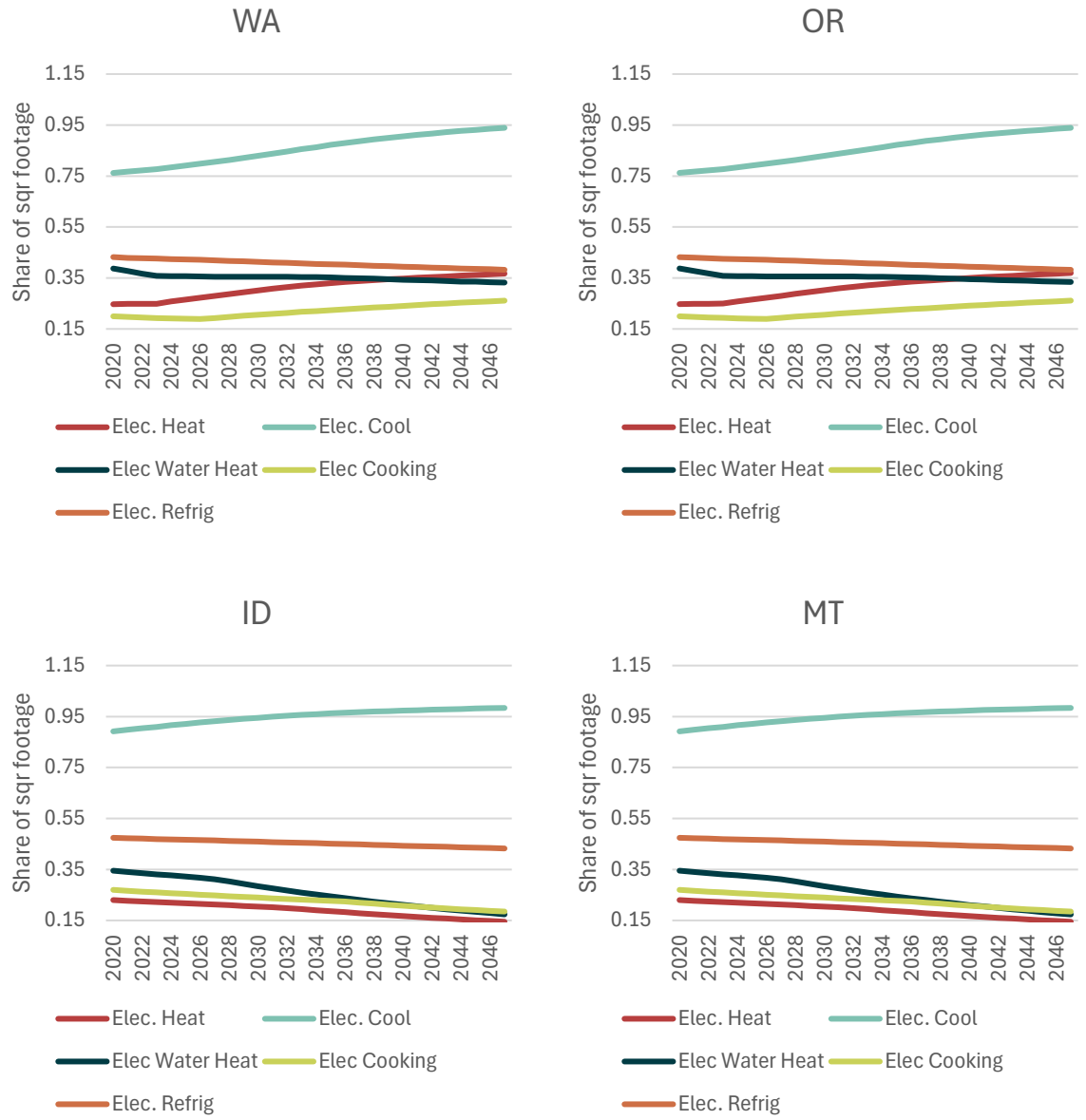
Saturation and Efficiency Levels

The estimate of historical saturation and efficiency levels of end-uses in commercial buildings are used to calibrate to historical demand. The estimated trajectory of future saturation and efficiency levels of end-uses in commercial buildings is an input to the forecast model to help project future demand. A stock and flow analysis was conducted by state and end-use to build up the data set.

The stock and flow analysis was set up to track the annual changes in end-uses in the commercial building stock over a period of 40 years, from 2010 to 2050. The commercial work relied heavily on information from the EIA AEO 2023, as well as the NEEA CBSA from 2009, 2014, 2019 and preliminary 2024. Adjustments were made to the saturation projections for heating for Washington (and Oregon) based on information from the 2021 Washington State Energy Codes, which went into effect in 2024. These codes encourage installation of efficient electric heat pumps in new construction. These adjustments pushed the saturation projections of electric heating up for Washington and were also applied to Oregon.

As in the residential sector, the projected overall saturation and efficiency levels for all sector square footage of the building stock is rolled up and input to the forecast model.

Figure F - 20: Commercial Sector End-Use Saturations by State

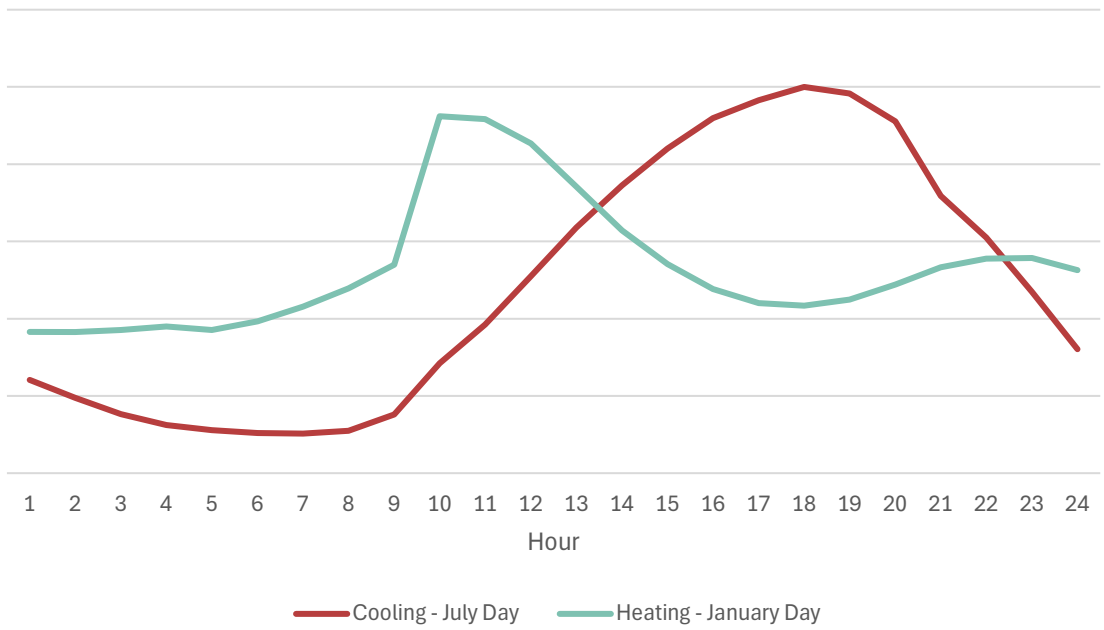


End-Use Shapes

To shape the commercial energy forecast, hourly, weather sensitive end-use demand shapes were generated for historical weather and the future weather patterns used in the forecast. These shapes are later applied to the estimate energy consumption from each end-use and calibrated with each zone's overall demand shape.

Weather sensitive hourly end-use shapes were derived using information from NREL Comstock[21] data sets. Figure F - 21 shows an example of the end-use shapes for space heating and cooling for a summer and winter day. As with the residential end-use example, the shapes represent an average kWh per unit demand for space heating and cooling. These shapes are applied to the forecast of seasonal heating and cooling demand (MWh) to generate an hourly forecast.

Figure F - 21: Commercial End-Use Hourly Shape Examples



High Building Electrification in the Commercial Sector

The High Growth and Late Growth forecast futures contain a high building electrification input data set. In this input data set, the Council boosted the electric saturations over the base level for space heating, water heating, and cooking. This was accomplished by:

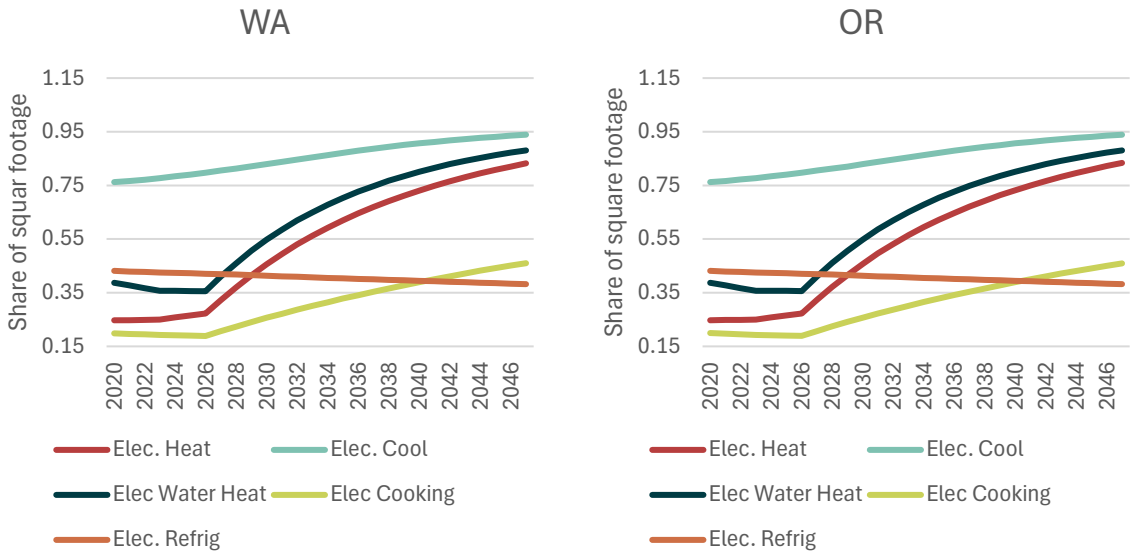
- Setting new building construction to be mostly electric – primarily this is setting space heat to heat pump technologies
- Moving natural gas end-uses to an as the gas unit ages out and needs to be replaced

As with the residential sector, only zones in the states of Washington and Oregon were modeled to have high building electrification.

[21] https://comstock.nrel.gov.

Figure F - 22 shows the higher saturation rates for electric end-uses by state. Idaho and W. Montana were left the same as the baseline projections.

Figure F - 22: Commercial Sector End-Use Saturations by High Electrification



Industrial Sector

An industrial demand variable is also an input to the SAE regression model. The key components that drive industrial demand in the model are:

1. An estimate of the energy intensity of each sector (MWh/employee)
2. An estimate of past and future employment for each sector, when available

The sectors in the model are based on the EIA North American Industrial Classification System (NAICS)[22] codes.

Table F - 11: Industrial Sector Codes

Sector	NAICS Code	Sector	NAICS Code
Agriculture	11	Glass	3272
Mining	21	Aluminum	3313
Construction	23	Iron and Steel	3311,3312
Food	311	Fabricated Metals	332

[22] https://www.eia.gov/tools/glossary/index.php?id=Industrial%20sector.

Sector	NAICS Code	Sector	NAICS Code
Wood	321	Machinery	333
Paper	322	Computer and Electronics	334
Bulk Chemical	3251,3252,3253	Electrical Appliances Components	335
Plastics and Rubber	326	Transportation Equipment	336
Cement Lime	3273,3274	Balance of Manufacturing	multiple

The industrial demand input is developed for each of the four states and applied to the zones within the state. The intensity component by sector (MWh/employee) is sourced from the EIA, which is a nation-wide average number. Past and future employment data by sector and each specific state was sourced from the S&P Global Market Intelligence Long-Term Annual report from January of 2025. This provides an outlook on employment changes in the overall industrial sector. The individual sector results are then combined to produce an overall industrial intensity input.

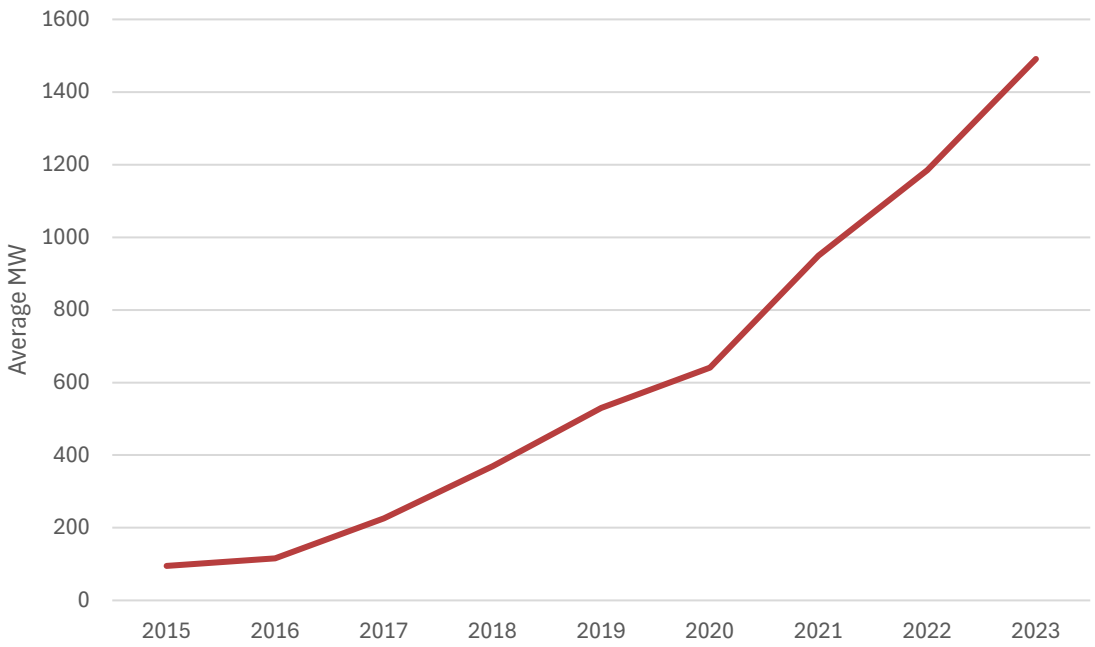
Data Center Forecast Input

Data centers and chip fabricators have the potential to add significant amounts of demand to the Northwest power system in the upcoming decades. While both industries have existed in the Northwest for decades, in the past few years there has been an increase in development, particularly for data centers. Part of this drive is due to the advancement of artificial intelligence. Data centers (single large loads) present a uniquely challenging forecast assignment. Unlike most load sources, the constraint on tech load growth may be due to infrastructure needs, construction timelines, permitting, supporting power infrastructure and supply, etc.

In the forecast model, data center demand is separated into its own demand category. Estimates of the data center demand are identified in the historical record and separated for the regression model fits. The demand forecast model then uses an externally derived data center forecast as an input.

The graph below shows an estimate of data center loads in the Northwest (the estimate is only for data centers and does not include chip fabrication load).

Figure F - 23: Estimate of Historical Data Center Demand

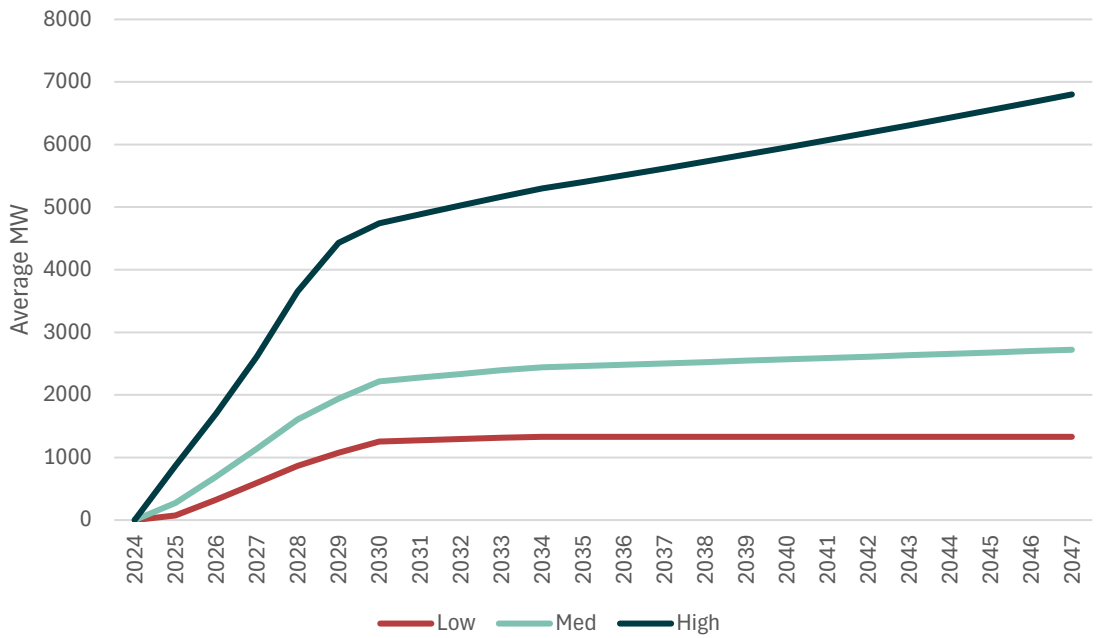


Due to challenges in acquiring actual data center load levels, these values are calculated using EIA sales data and utility data (when available). They are estimates and likely differ from actual values. Notably, this estimate, and the forward-looking forecast, may not include smaller embedded data centers and data closets. The EIA data is aggregated by residential, commercial, and industrial sales. When a utility is reporting high levels of sales growth in the commercial or industrial segment, and there are also known data centers entering the utility service area, the Council assumes the sales growth is attributable to either data centers or chip fabs. This approximation method may overcount the amount of tech growth in utilities that are seeing other industrial/commercial growth concurrent with tech growth, and it may undercount tech growth for utilities experiencing decay in non-tech industrial/commercial sales.

Historical data center demand is not evenly distributed across the forecast zones (balancing authorities) in the region. The zones most impacted recently include BPA, GCPD, PACW, PGE and DOPD.

There is significant uncertainty in future data center growth for the region. Therefore, three trajectories of future data center demand were developed as a forecast input – a low, medium and high. The medium input was used for the Late Growth and Mixed Bag futures, the high input for the High Growth and Early Growth futures, and the low input for the Low Growth future. The input represents expected incremental data center demand starting from year 2024 for each forecast zone. Figure F – 24 shows the rolled-up region view; all three outlooks suggest a good chance of rapid growth in the near term, but past 2030, the growth picture becomes more uncertain

Figure F - 24: Data Center Input for region



The medium input, for utilities with past data center growth, assumes that data centers will continue to arrive in the utility service area at the same magnitude they have arrived over the past four years. For utilities that are projecting data center load at large scale for the first time, the medium forecast assumes that 80% of the projected load materializes.

The low forecast uses utility IRP low forecasts if available. If a low forecast is not available, either 40% of the utility forecast for new data center growth is used (if the utility does not have identifiable data center growth in their sales data), or the data center average growth over the past eight years (if the utility has data center growth in their sale data).

The high forecast employs utility IRP medium-case forecasts when available, and/or 100% of announced data center projects (at time of forecast publication).

Electric Vehicles

Electric cars, vans, trucks, and buses are relatively recent and rapidly growing electric end-use. Electricity consumption for transportation is very impactful to the demand forecast for several reasons:

1. It is a steadily growing load which will drive annual energy consumption
2. It affects multiple sectors – residential and commercial primarily
3. Residential charging often occurs during times when the system is peaking, therefore it presents an opportunity for demand-side management
4. It is concentrated in specific locations, primarily large urban centers

In late 2025, there were approximately 393,000 electric vehicles registered in the states of Oregon and Washington. This is nearly double the number of electric vehicles in 2022. Oregon and Washington have both adopted the California Clean Cars II rules which will require 100% of new vehicles sales to be zero-emission by 2035.

Transportation demand is an input to the demand forecast model. The model requires three main inputs:

1. Annual demand – historical and forecast (MWh) for light duty vehicles (LDV), medium and heavy-duty vehicles (MDV, HDV) and busses by forecast zone
2. An allocation of vehicle charging locations – home, workplace, public
3. Vehicle charging profile options (managed and unmanaged)

In the model, electric vehicle demand is assigned to the sector where the vehicle is expected to be charged. The demand is shaped and layered onto the residential and commercial demand depending on the charging allocation assignment and profile.

Input Electric Vehicle Demand

The input data set includes a projection of annual energy (MWh) by vehicle type and forecast zone out through year 2047. Two input data sets were developed: a higher case, and a lower case that is roughly 15% less (in terms of demand). Both projections are designed to meet Oregon and Washington state policies that 100% of new sales are to be zero-emission vehicles by 2035. The lower case assumes that the overall demand for transportation is less, meaning there are fewer cars on the road. A data set built up from historical LDV registration by state was used to set a base of vehicle stock. The states of Oregon[23] and Washington[24] maintain electric vehicle dashboards that provide the number of electric vehicles registered and in some cases the county. For Idaho and Montana, a variety of sources were used to estimate the electric vehicle stock, including the US Department of Energy Alternative Fuels Data Center.[25] County data was used to allocate the state-wide EVs to specific forecast zones. Estimates of annual vehicle miles traveled and kWh per mile were used to estimate annual historical demand.

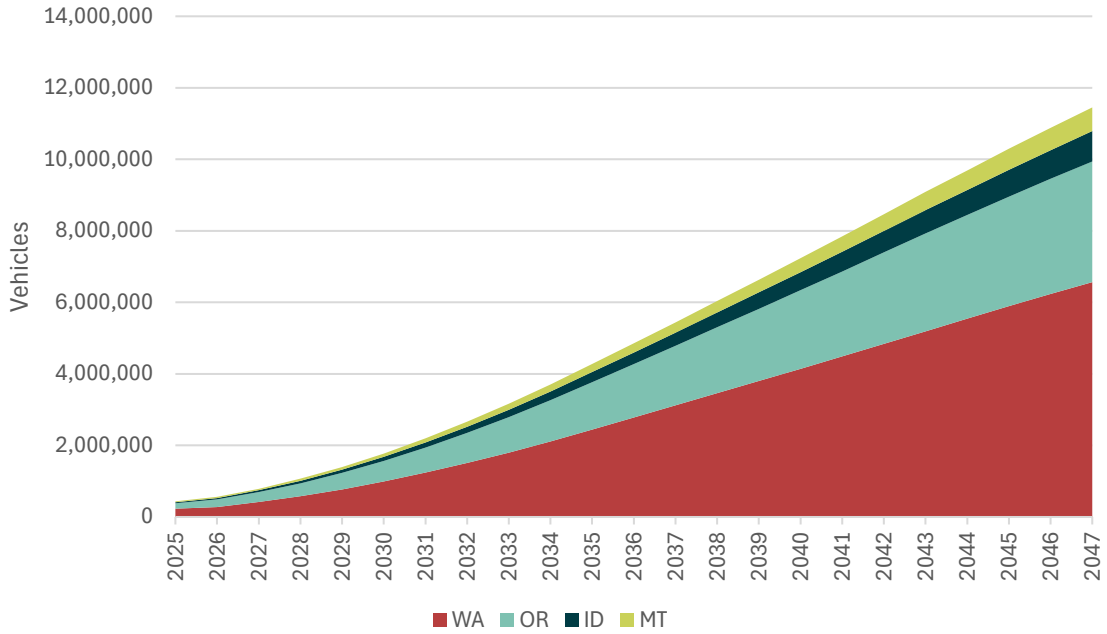
A forward projection of EVs was developed using the system dynamics model Energy Policy Simulator (EPS) from Energy Innovations and RMI.[26] This tool provides state level forecast with breakout of vehicles by fuel and type. Judgement was also applied to the forecast, to best reflect the region's

[23] https://www.oregon.gov/energy/Data-and-Reports/Pages/Oregon-Electric-Vehicle-Dashboard.aspx.
[24] https://data.wa.gov/Transportation/Electric-Vehicle-Population-Data/f6w7-q2d2/about_data.
[25] https://afdc.energy.gov/transatlas#/?year=2023&state=ID&fuel=ELEC.
[26] https://energypolicy.solutions.

transportation system. Data from CALSTART[27] was used to inform the forecast of electric buses, and trucking (MDV, HDV).

Figure F - 25 through Figure F - 27 show the transportation input to the forecast model for the higher transportation case.

Figure F - 25: Projected LDV Electric Vehicles by State



[27] https://calstart.org.

Figure F - 26: Projected LDV Demand by Zone

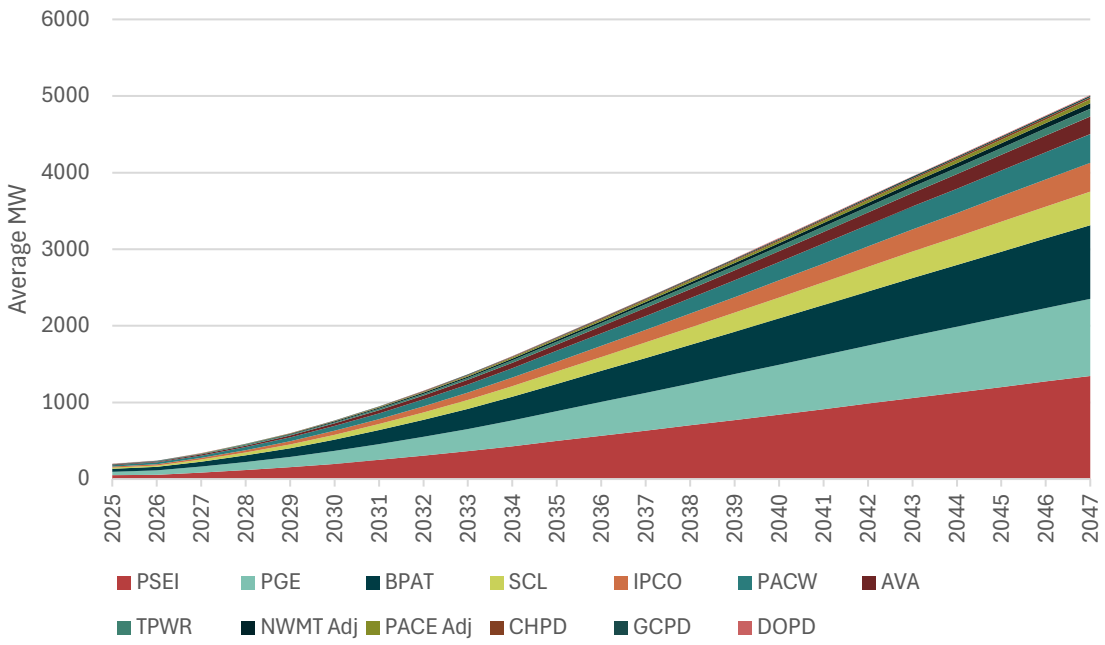
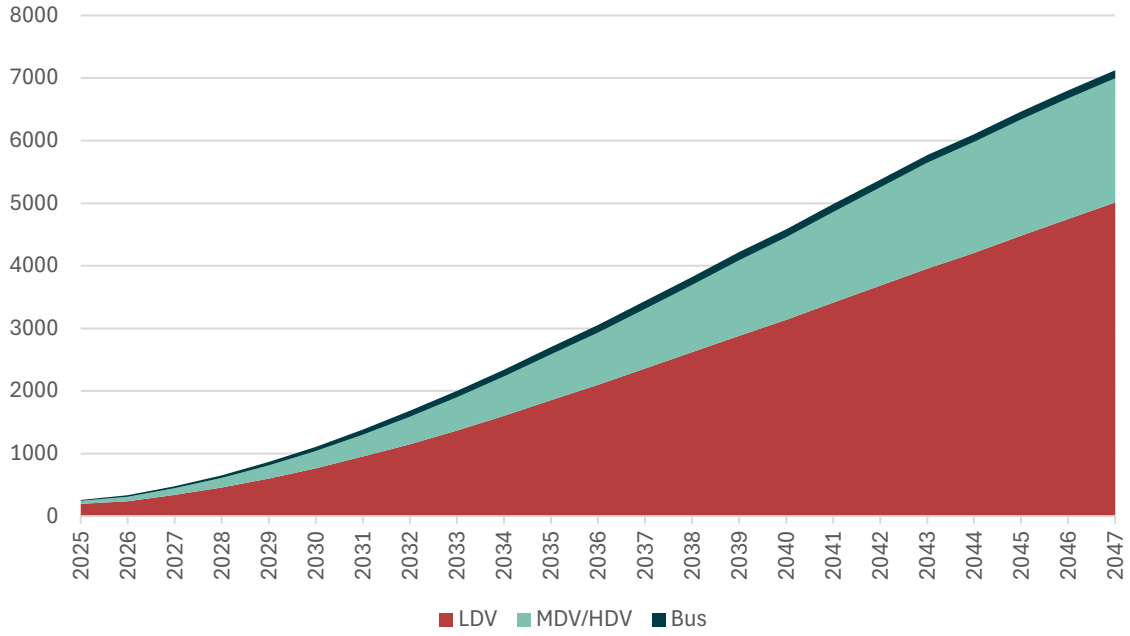


Figure F - 27: Projected Transportation Demand by Vehicle Class



Electric Vehicle Charging Profiles

Multiple charging profiles were developed to apply to the vehicle energy demand. The LDV class profiles were developed using the US Department of Energy/NREL EVI-Pro Lite tool[28]. The MDV/HDV and bus charging profiles were sourced from the California Energy Commission (CEC)[29].

Table F - 12: Charging Profile Suite

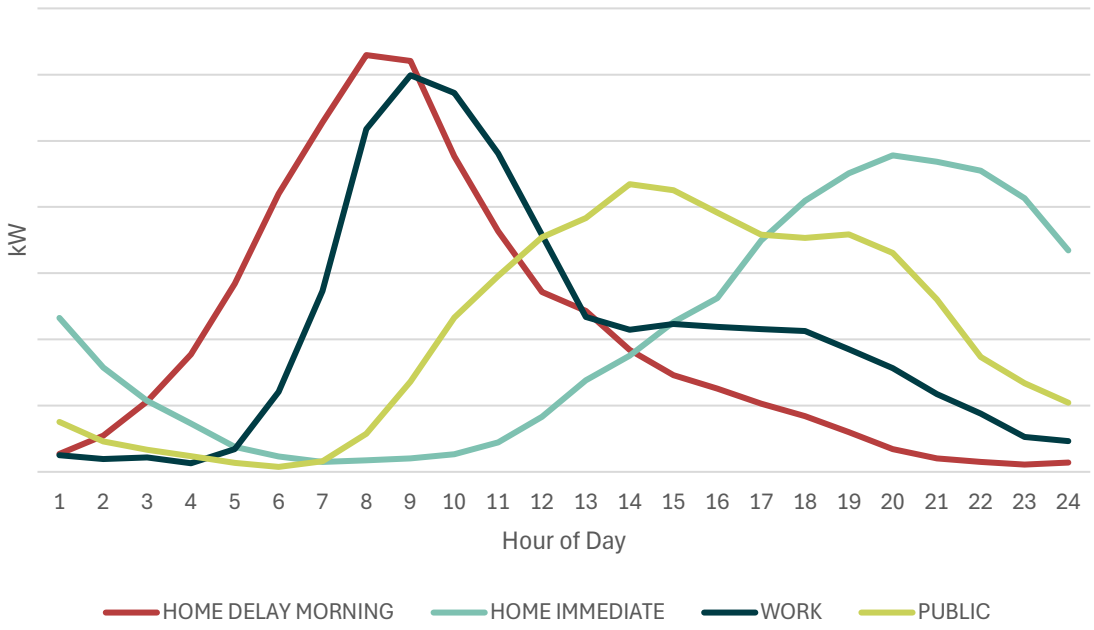
Class	Type	Profile	Source
LDV	Home Level 1 Home Level 2	Immediate Delayed Midnight (managed) Delayed Morning (managed)	NREL EVI-Pro Lite
LDV	Work Level 2 Public Level 2 Public DC Fast	Immediate	NREL EVI-Pro Lite
HDV, MDV, Bus			CEC

Much of the LDV charging is expected to take place at home. This demand is allocated to the residential sector. The charging shape that is used in the forecast is primarily the immediate (un-managed) profile, which peaks in the evening as commuters return home after the workday and plug their vehicle in. The Council expect over time that the LDV charging demand will be managed, possibly through implementations of time of use rates, but we kept much of the charging in the forecast to be un-managed. This allows the Council to assess the potential of demand response in relation to other resources to ultimately inform the Ninth Power Plan's cost-effective resource strategy.[30]

Another finding from the work is that simply spreading out the EV charge over locations – home, work, and public can significantly even out the demand over the day. For example, the Figure F - 28 shows the model EV daily profiles for multiple sites.

[28] https://afdc.energy.gov/evi-x-toolbox#/evi-pro-loads.
[29] https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection.
[30] More information on the demand response potential is available in Technical Appendix I – Demand Response Methodology and Potential.

Figure F - 28: Daily EV Charging Profiles



Rooftop Solar

Rooftop photovoltaic (PV) pertains to the use of solar panels mounted on top of buildings, to generate electricity from sunlight. It may also be referred to as behind the meter solar (BTM). The electricity produced can be used on-site at the residence or business to reduce customer demands on the grid. Though the Northwest traditionally has been a relatively small player in the rooftop solar market, installations of PV systems have been growing in recent years and have an impact on future demand.

We developed a data set with historical and forecast annual PV capacity by sector (Res, Com, Ind) for each forecast zone. The amount and shape of electricity generated by the installed PV capacity is calculated in the demand model using location-specific global horizontal irradiance (GHI) values. This solar generation is then subtracted from the demand in the sector and zone that it was produced in.

Because rooftop solar is becoming more available in the Northwest, the Council decided to include some rooftop solar potential as a demand side resource option to test in scenario modeling.[31] Therefore, the Council including only a conservative projection of rooftop solar demand reduction in the demand forecast better allows the resource model to select additional solar installation levels if cost effective as compared to other resource options.

[31] More information is available in Technical Appendix J – Rooftop Solar Methodology and Potential

Rooftop Solar Installations in the Northwest

To support the forecasting work, the Council compiled complete data sets of PV installations by zone and sector from 2011 through 2025. Data from the EIA 861[32] report was especially useful, as well as EIA Short[33] and Long Term Energy[34] Outlooks.

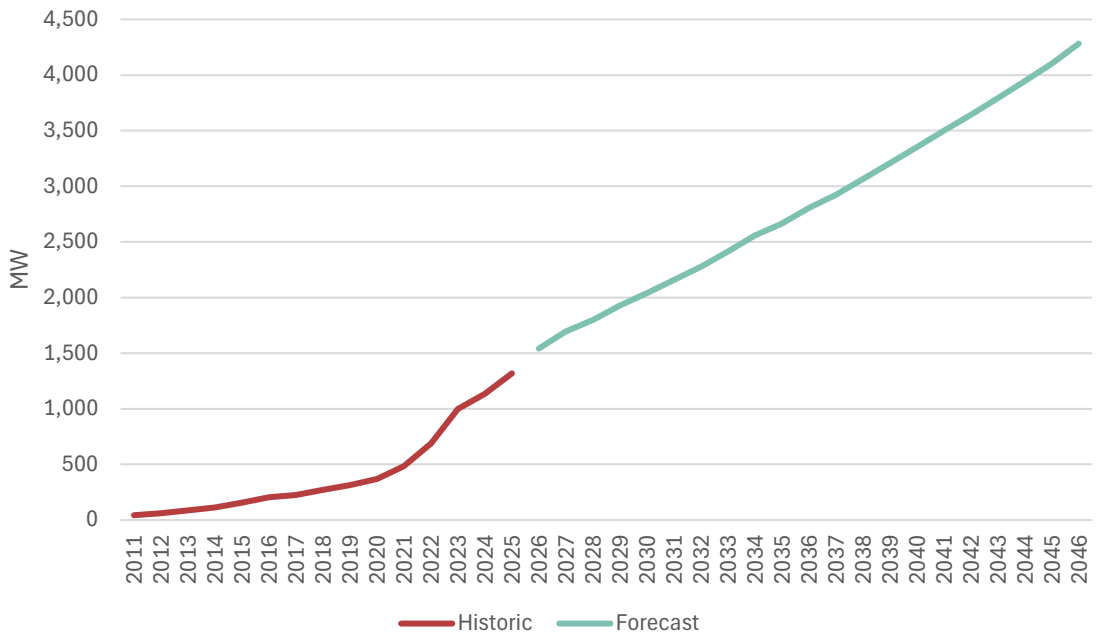
Some key findings of the PV work:

1. 2023 was a record year of installs in the region – around 315 MW – which continued a strong trend of growth since 2020
2. 2024 installs declined from 2023 – to around 134 MW – possible factors include higher financing costs and a few installer companies filing for bankruptcy
3. The Northwest is a small player in the solar market, but does seem to be following national trends
4. Installs rebounded slightly in 2025 to 185 MW, and EIA and industry groups expect continued growth to follow
5. Installed rooftop PV in the region as of 2025 is 1,318 MW, meaning 24% of the current existing capacity was installed in a single year (2023)

To create a projection of future PV installation in the region, the Council developed a basic trend model (Brown's Double Exponential Smoothing Method) based on historical data combined with judgment gleaned from the EIA short- and long-term outlooks. Figure F - 29 and Figure F - 30 below display the regional results – both actual installations and forecast.

[32] https://www.eia.gov/electricity/data/eia861.
[33] https://www.eia.gov/outlooks/steo.
[34] https://www.eia.gov/outlooks/aeo.

Figure F - 29: Installed PV Capacity in the Region

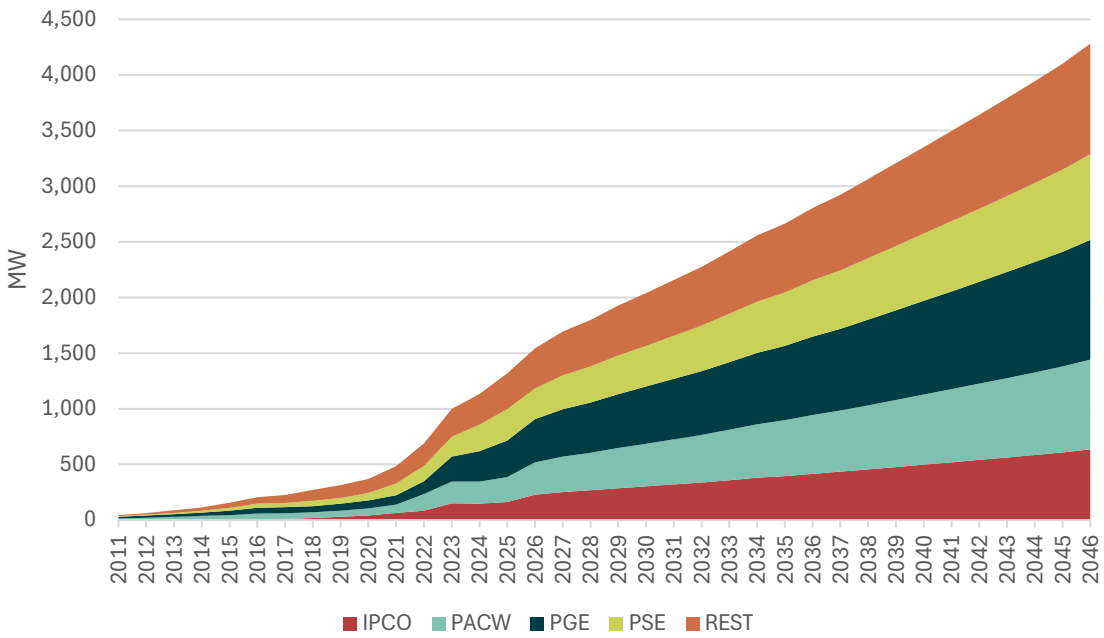


Much of the installed PV capacity is projected to be in the residential sector and is concentrated primarily (75%) in four zones (balancing authorities) – Idaho Power, PacifiCorp West, Portland General, and Puget Sound Energy.

In addition to the solar embedded in the demand forecast, rooftop solar is also treated as a resource option in the power plan to evaluate cost-effective strategies. The 20-year potential for rooftop solar generation is estimated to be 4,273 average MW, which corresponds to nearly 27,000 MW of capacity[35].

[35] See Appendix J – Rooftop Solar Methodology and Potential.

Figure F - 30: Installed PV Capacity by Zone



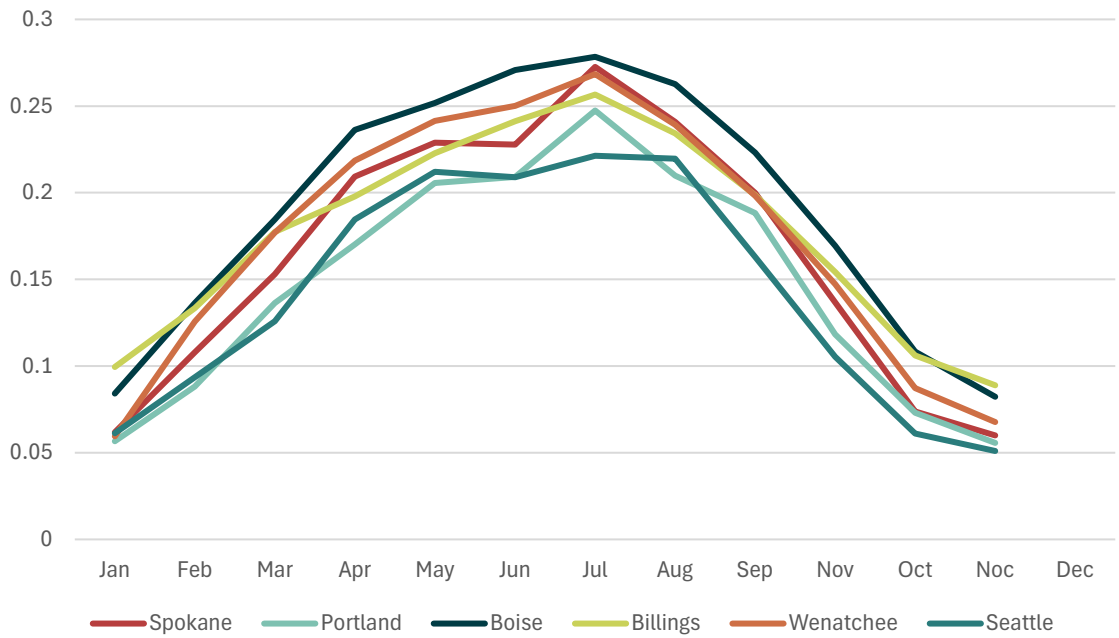
Rooftop Solar Shapes and Generation

Solar generation profiles were developed and input to the demand model to spin PV capacity into generation, as a function of GHI. Solar generation data from the National Renewable Energy Lab (NREL)[36] was used to model locational profiles. Note that the rooftop solar profiles here are very similar but not an exact one-to-one match with the full climate model informed profiles.[37]

The overall regional rooftop capacity factor (generation/capacity) is around 15.6%. For example, 2000 MW of installed capacity would produce 310 aMW. Generation varies by location and season. See Figure F - 31 for an example of the solar capacity factors by month.

[36] https://atb.nrel.gov/electricity/2024/residential_pv.
[37] See Appendix D – Climate Model Data and Assumptions.

Figure F - 31: Monthly Solar Generation Profiles



In the summer, the region's demand often ramps up in the late afternoon. There is still sizeable solar generation during this time, which is beneficial in lowering the peak requirements. However, in the winter, the peak often occurs in early morning when there is little to no solar generation.

Hydrogen Load Forecast

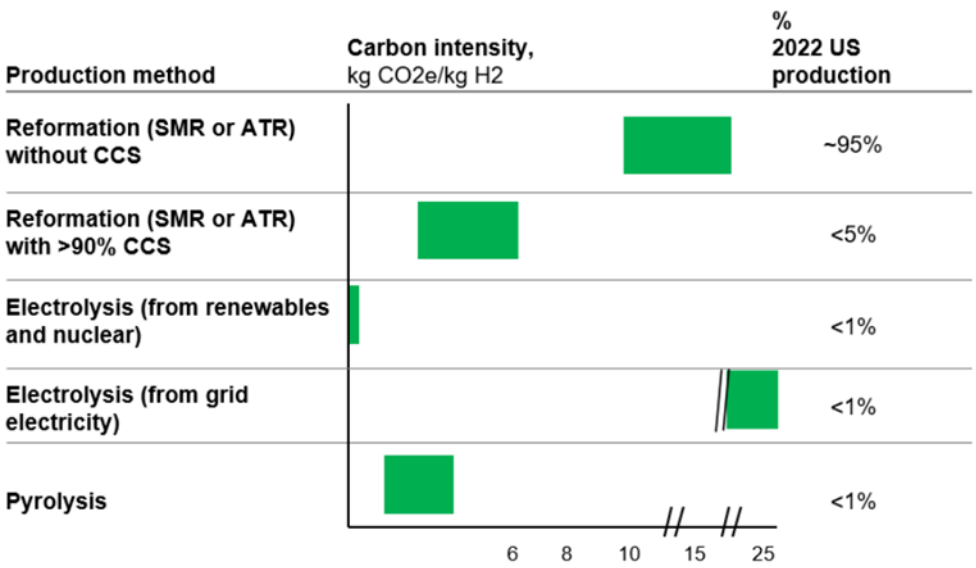
For the Ninth Power Plan, a hydrogen fuel forecast was developed to represent the electricity required to create clean hydrogen in the Northwest. This forecast is specific to hydrogen used for non-power system uses, like the industrial sector. It can also be viewed as a rough proxy for general industrial and medium/heavy duty transportation decarbonization via electrification. For the Ninth Power Plan, the hydrogen demand is modeled to be curtailable, therefore this demand is not included in the peak forecast, but it is included in the energy forecast.

Hydrogen, if created using low carbon processes, can be used to decarbonize hard-to-reach economic sectors like high-heat industrial applications and medium/heavy duty transportation. Hydrogen can be used as a fuel directly, or as an intermediary step when developing other fuels like ammonia or drop in liquid fuels.

Hydrogen is not commonly found in nature and typically requires another energy source to create. Today, in the US, most hydrogen is made with natural gas as the primary energy source. If clean electricity is used as the primary energy input, hydrogen can be created with a low carbon footprint. Other non-electric hydrogen creation sources can yield low carbon hydrogen as well, including natural gas if carbon capture is employed. The figure below is taken from a 2023 US Department of Energy

report and estimates the carbon associated with creating hydrogen via different energy inputs and processes.[38]

Figure F - 32: Hydrogen Production Carbon Intensities



Little, if any, hydrogen is produced in the Northwest today using electricity as the primary energy source.[39] Resultingly, the Ninth Plan Northwest hydrogen demand forecast is rough due to nascent nature of the industry. The forecast largely relies on two sources. First is publicly shared information from the Northwest hydrogen hub. Second is the US Department of Energy's 2023 report, "U.S. National Clean Hydrogen Strategy and Roadmap". The high-level steps used to create the forecast follow:

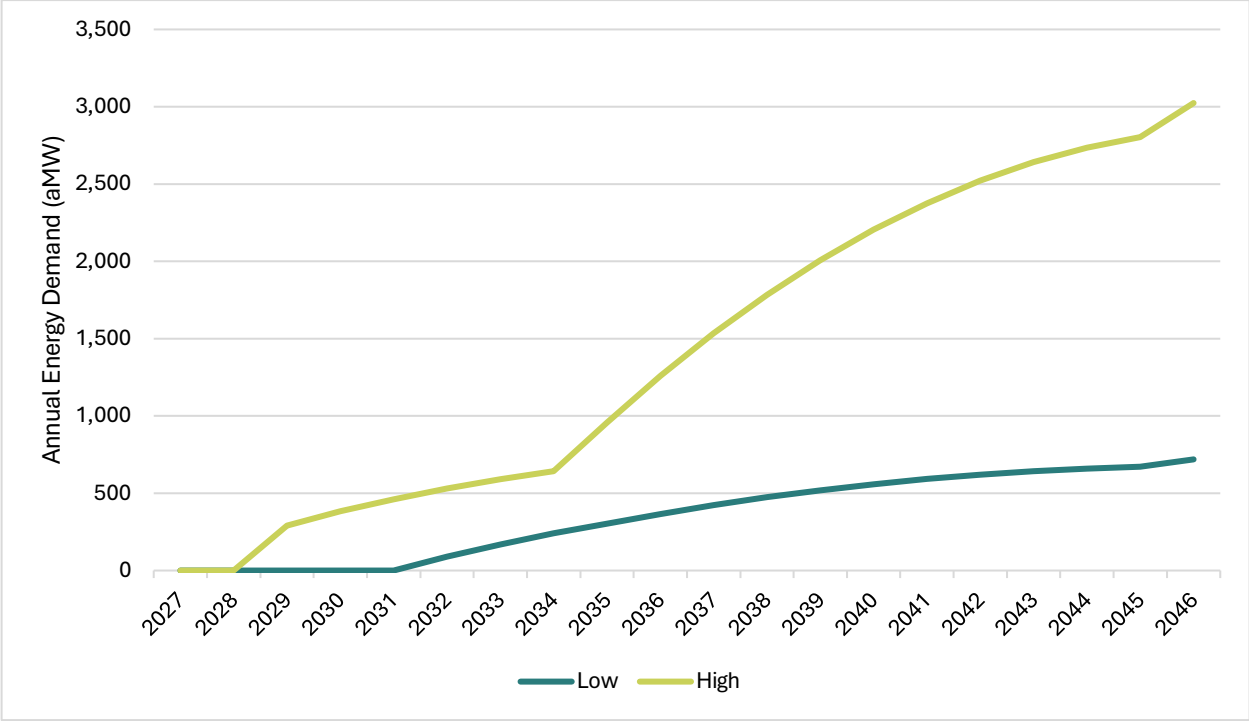
1. Both forecasts (high and low) start with estimates of hydrogen production from the Northwest Hydrogen Hub. For the high case, the hub projects are assumed to come online in 2029, and in the low case, 2032. Production is assumed to be ramped up smoothly over the following years until a level of 0.11 MMT/year is reached for the low case, or 0.15 MMT/year for the high case.
2. After the Northwest Hydrogen Hub ramp, the high case shows accelerating hydrogen usage. This is based on the national DOE "Clean Hydrogen Strategy and Roadmap" report that came out a few years ago. The report is national, a Northwest share is made by prorating how much energy the Northwest uses for non-electric industrial usages and transportation. This ends up being around 1.5 MMT/year in 2050. The low case hydrogen usage grows at the same speed as it did over the six-year hydrogen hub low ramp in, reaching 0.35 MMT/year in 2050.

[38] US DOE, 2023, U.S. National Clean Hydrogen Strategy and Roadmap.
[39] At time of writing the 5 MW Douglas County renewable hydrogen pilot facility was just coming online

In both the low and high case, an increasing amount of hydrogen is assumed to be either produced outside of the Northwest (and imported in) or produced in the Northwest using a non-electric feedstock. By 2045 half the hydrogen in the forecast comes from a non-electric facing technology. This essentially cuts the electric load forecast in half for 2045 compared to all the hydrogen being produced in the Northwest using electrolysis.

The final forecast, for the low and high pathways, are shown below.

Figure F - 33: Forecast Range for Hydrogen Demand



After the Ninth Plan hydrogen forecast was finished, the Federal government withdrew grant funding for the Northwest Hydrogen Hub (originally a grant of up to 1 billion dollars was awarded). This may negatively impact the development of hydrogen projects in the Northwest, particularly in the near-term. In the long term, local and state governments in the Northwest have decarbonization goals for the industrial and heavy-duty-vehicle / marine / aviation sectors. The Ninth Plan does not include a specific decarbonization focused forecast for those sectors. While the hydrogen forecast was created specifically for electric loads associated with hydrogen production, it can also be viewed as a rough proxy for electric loads associated with decarbonizing those sectors.

Energy Shaping

The monthly energy for each zone that is produced by the energy regression models are shaped into daily and hourly intervals. The end-use shapes are applied to the disaggregated energy forecast results. In addition, individual hourly profiles are built out for each of the forecast zones. A regression model is fit for each separate hour (24 in total) for the zones. The inputs to the model include hourly

historical demand data, historical weather data (HDD, CDD), calendar month, day of week, and holidays. The hourly shaping models are then used to build out a comprehensive, weather sensitive zonal demand profile based on historical data and comprised of a system, heat, cool and baseline profile. This is the profile that the shaped end-use demand is calibrated to.

Finally, new technology demand is layered on based on input shapes. This can include the electric vehicle demand and any additional building electrification. For example, for the futures that include high building electrification, the additional heating, cooling, water heating and cooking demand is layered onto the demand profile using the specific end-use shape associated with the end-use. For instance, for space heating, it is assumed that the technology used is a heat pump, so the specific heat pump profile is applied to all new space heating electrification demand.

Forecast Results

The frozen-efficiency demand forecast shows robust demand growth in nearly all of the forecast futures. Figures 34 and 35 display the results of the forecast for the region's annual demand energy and demand peak for the three climate model weather patterns. Please note that Hydrogen demand is excluded from the energy and peak results in the discussion and figures. To understand the full future forecast for energy, add the additional hydrogen as forecast and shown in Figure F - 32. The Council assumed the hydrogen load was elastic and is not in the peak forecast.

Figure F - 34: Annual Forecast Energy Range for Region

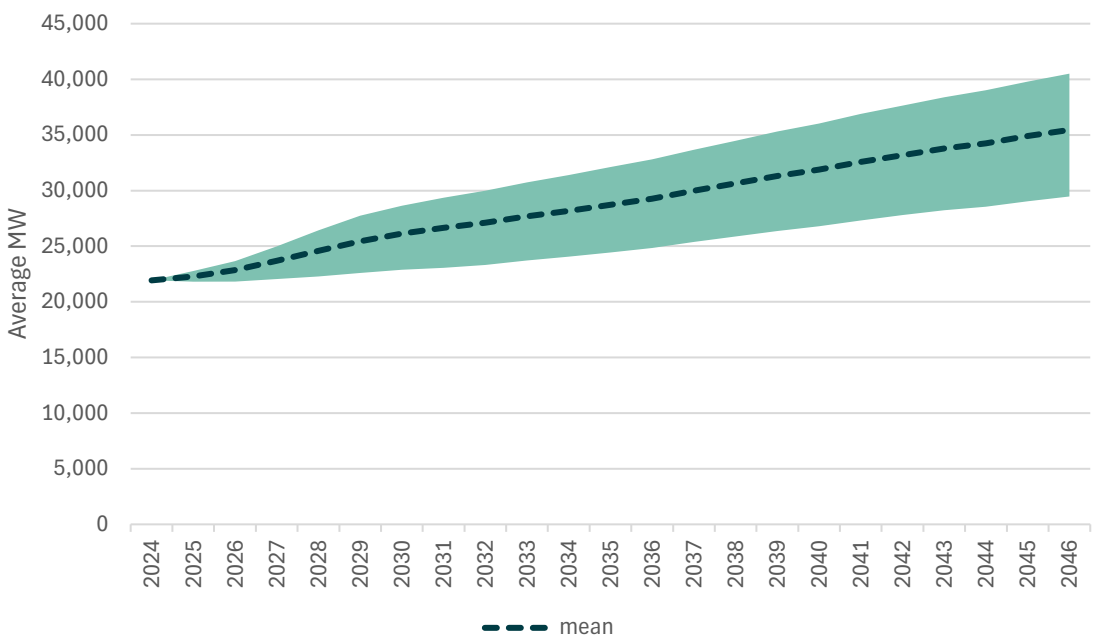
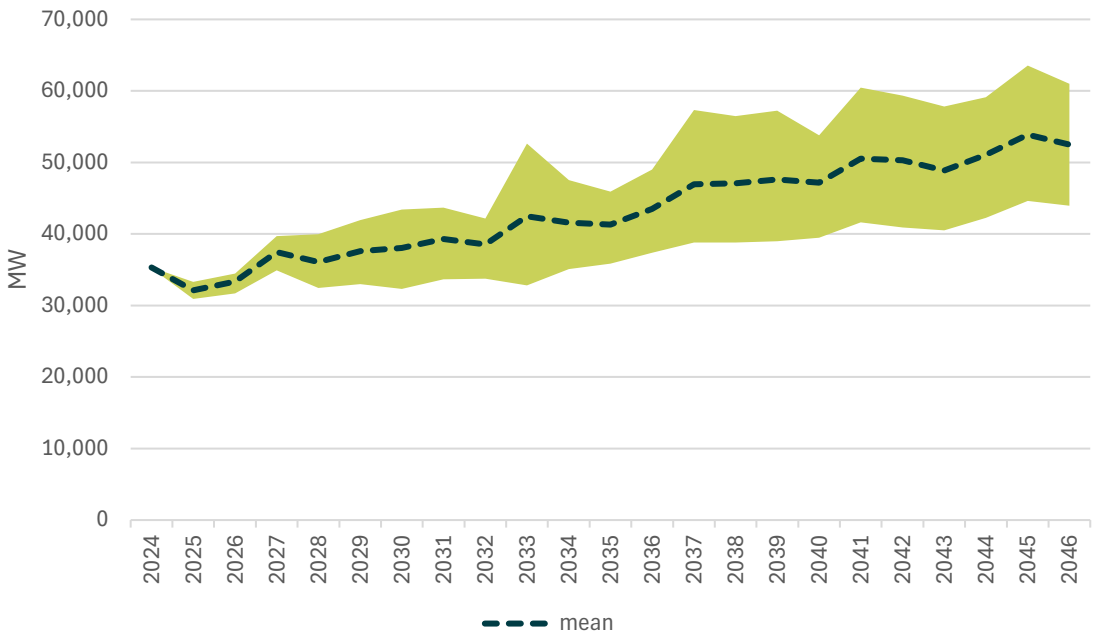


Figure F - 35: Annual Forecast Peak Range for Region



As expected, peak demand is much more volatile, since even though an overall weather pattern may be mild in terms of overall heating degree and cooling degree days, it may be sprinkled with extreme cold and/or hot temperature events.

Looking at the forecast horizon from 2025 through 2046, average annual energy growth rates range from 1.4% to 2.8%. In terms of total energy growth in average MW, the futures range from a high of 17.820 aMW to a low of 7,645 aMW.

Forecast average annual peak rates are growing faster, ranging from a low of 1.8% to 3.1%.

Figure F - 36: Energy Growth Rate

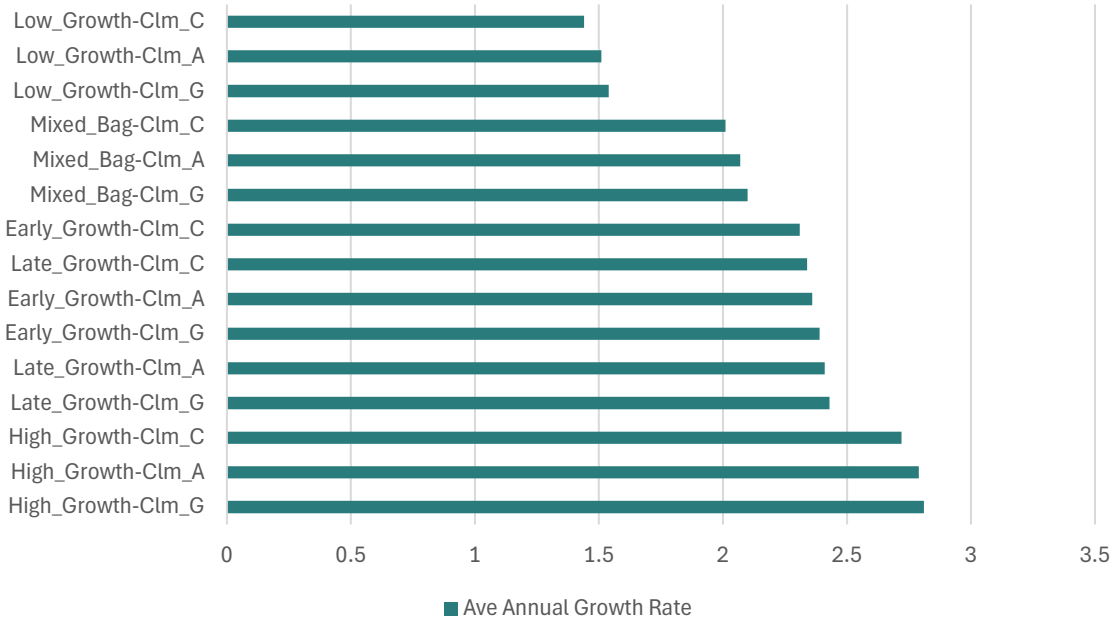


Figure F - 37: Energy Growth (aMW)

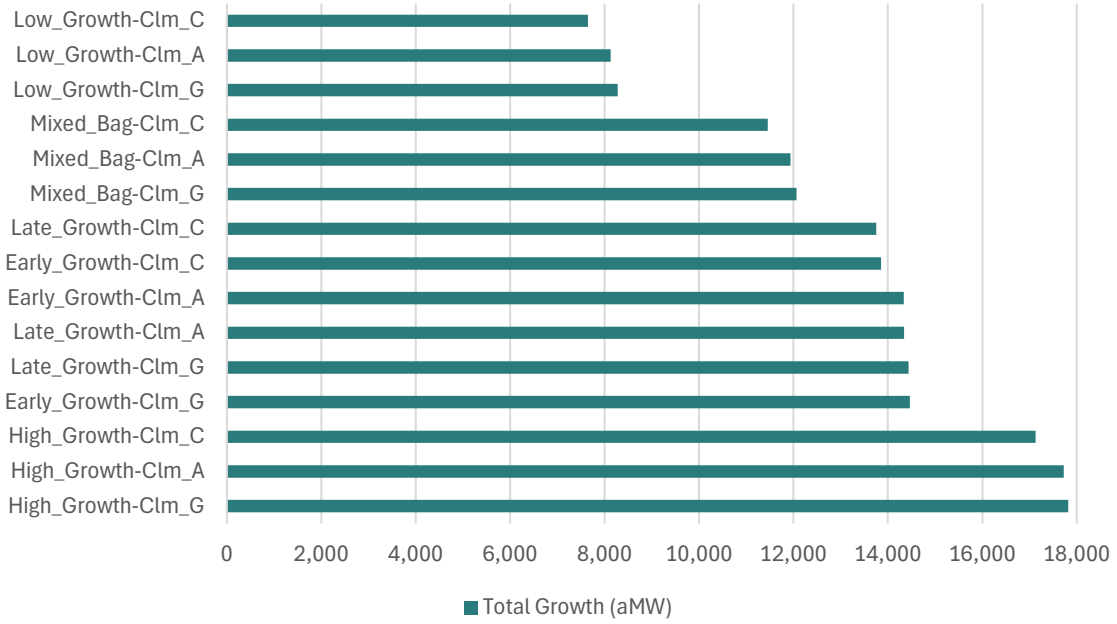
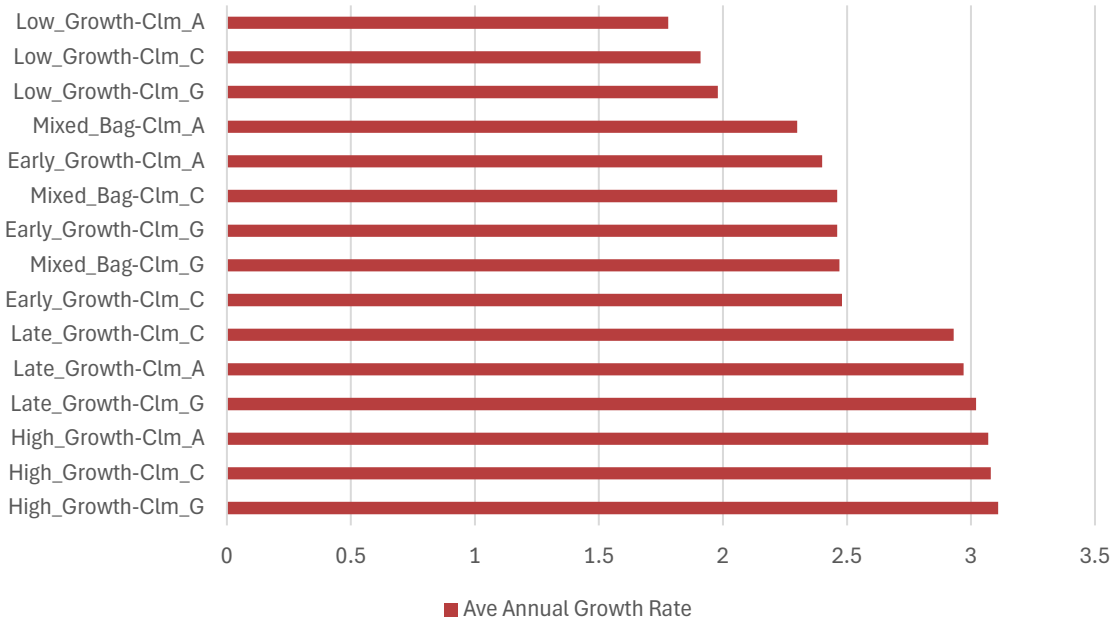


Figure F - 38: Peak



Energy

The forecast projects growth across the residential, commercial, industrial, electric vehicle, and data center sectors. Note that for the data center and electric vehicle sectors, the demand shown is incremental to 2024.

Looking at the sector level, the range of forecast uncertainty varies. Figure F - 39 shows the range of demand by sector, across all economic pathways and weather patterns. Note, in this figure, the residential and commercial sectors contain the electric vehicle charging and building electrification which are embedded within those sectors.

Figure F - 39: Regional Energy Forecast Range by Sector

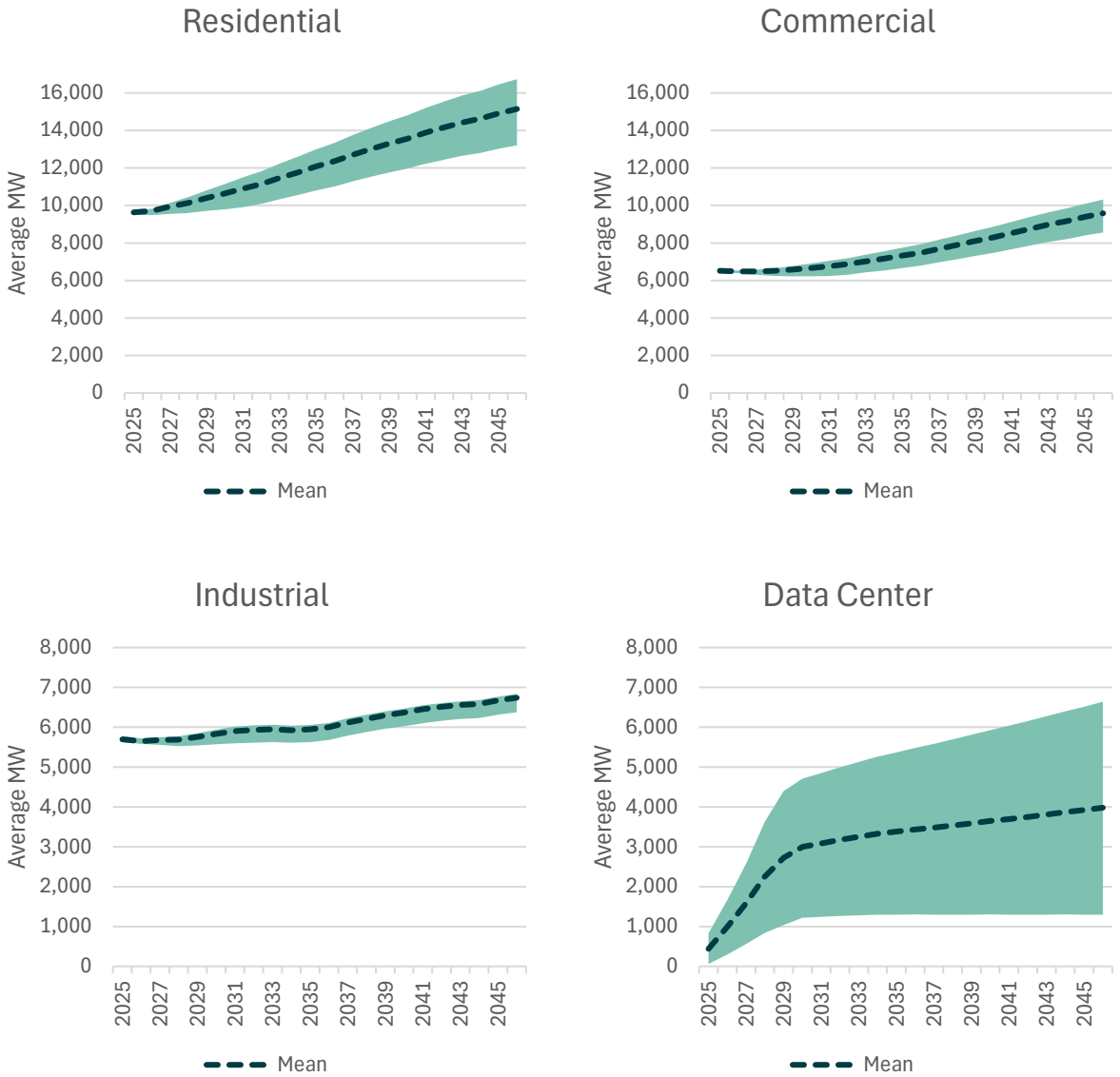
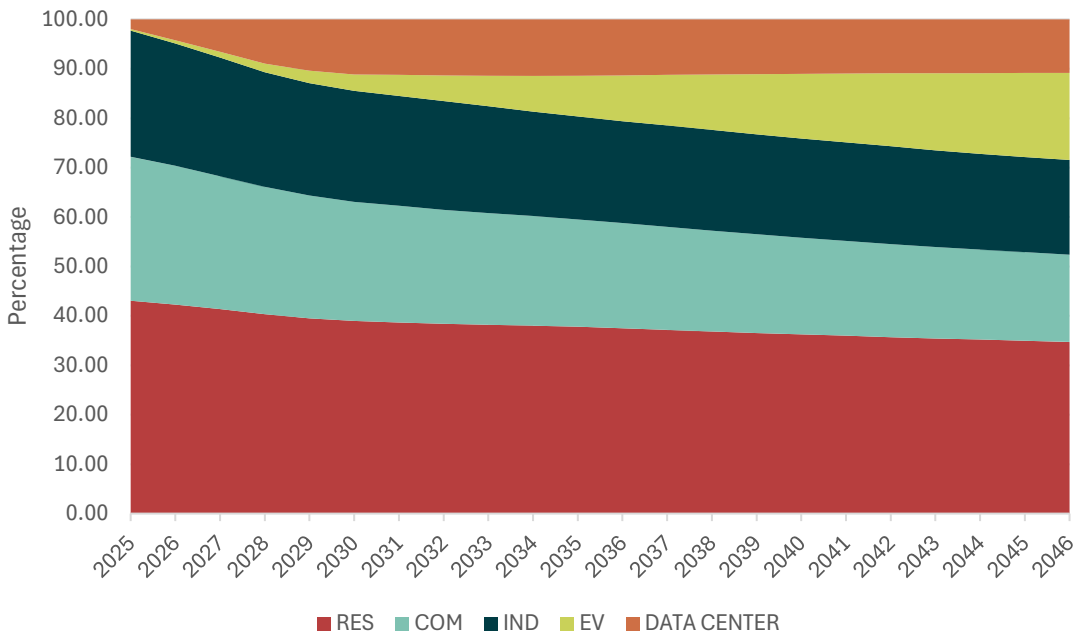


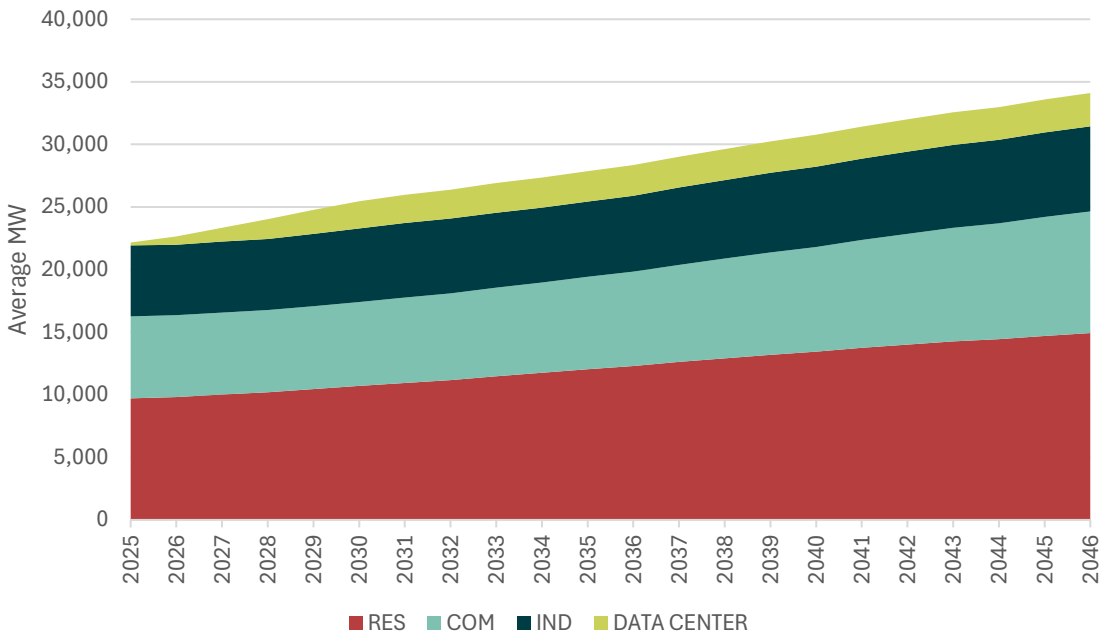
Figure F - 40 shows the average breakout of the forecast by sector across all the futures, expressed as a percentage of the total annual demand. In this representation, the electric vehicle demand is pulled out of the residential and commercial sectors.

Figure F - 40: Regional Energy Forecast Range by Sector across all Futures



For an example of a specific future, Figure F - 41 shows the forecast for Mixed Bag Climate A. with the electric vehicle demand included in the residential and commercial sectors.

Figure F - 41: Regional Energy Forecast Mixed Bag – Climate A

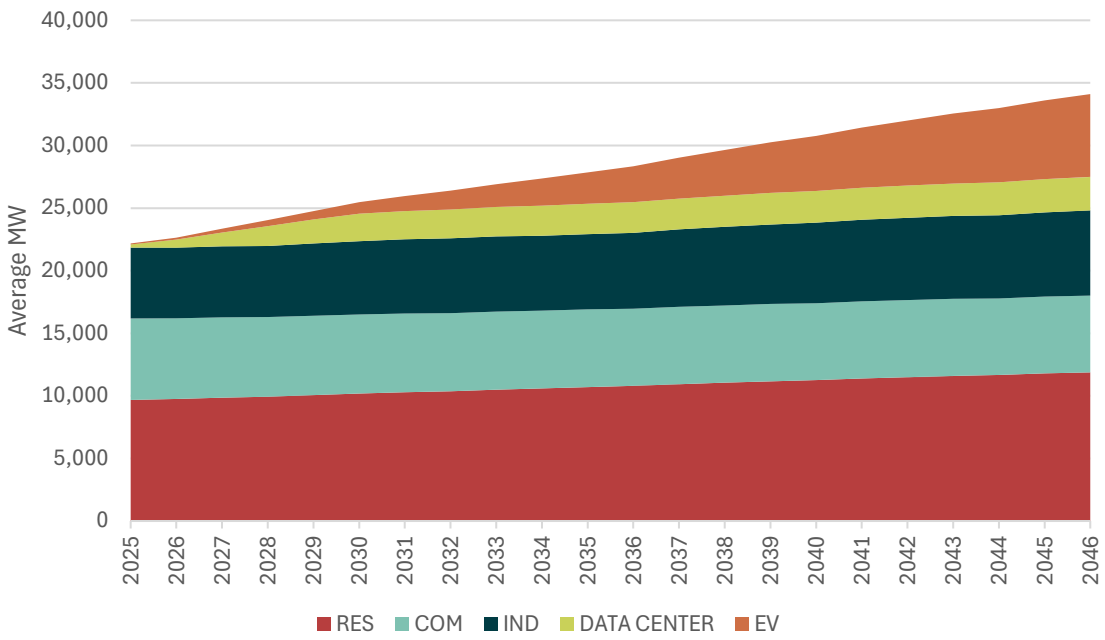


In this future, the total growth in average MW (aMW) from 2025 to 2046 is 11,937 aMW. Of this growth in energy:

- 44% is from residential
- 26.5% is from commercial
- 9.5% is from industrial
- 20% is from data centers

Much of the residential and commercial growth is tied to electric vehicle load growth. If we pull out the electric vehicle demand out of the residential and commercial sectors, we see more muted growth in residential and commercial.

Figure F - 42: Regional Energy Forecast Mixed Bag – Climate A with EV Separate



Electric vehicles alone accounts for over half of the overall demand growth in this future. The residential sector, excluding electric vehicles, accounts for 18% of the growth, and the commercial sector is flat.

Figure F - 43 displays the forecast for the High Growth future, with further disaggregation of the electric vehicle and building electrification demand.

Figure F - 43: Regional Energy Forecast High Growth

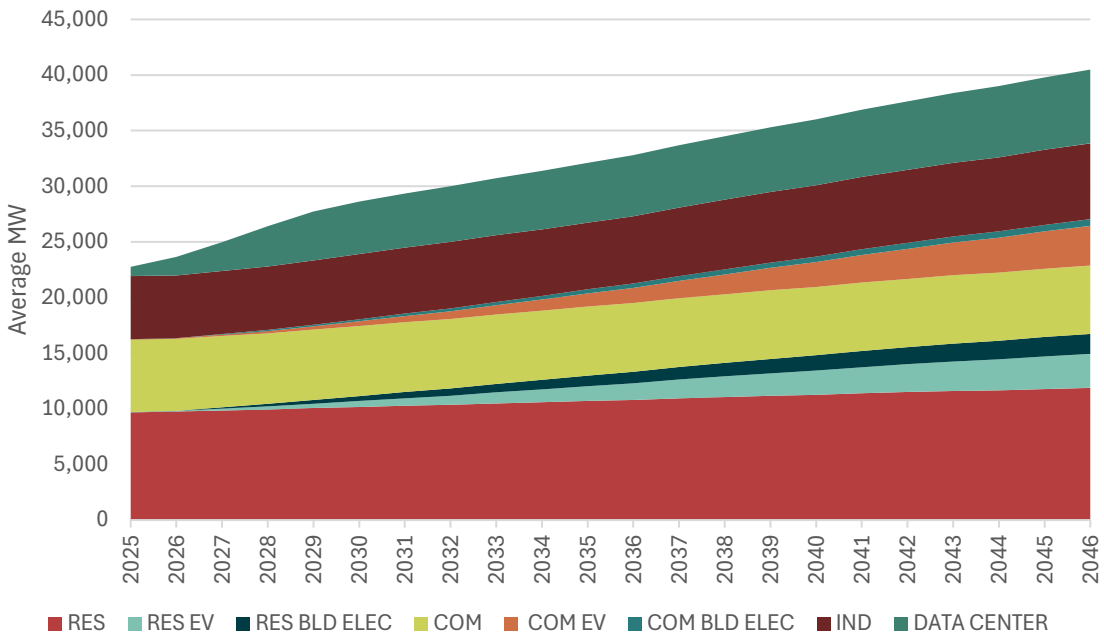


Table F - 13 shows the percentage of the overall system-wide growth that each sector contributes in each future with the Climate A pattern. The total energy growth is the delta between the forecast in the years of 2046 and 2025.

Table F - 13: Percentage of the Overall Growth by Sector Across all Climate Futures

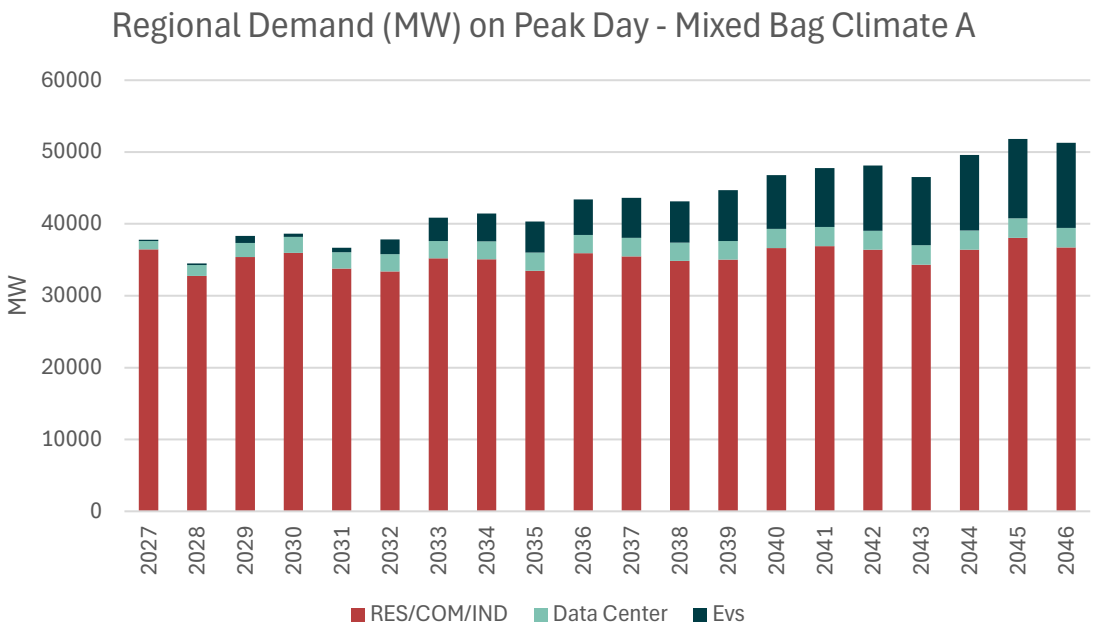
Future	RES	COM	IND	Data Center	EV	Bld. Elec.
Low Growth	16.5	-10.3	9.0	15.4	69.4	0
Mixed Bag	18.0	-3.5	9.5	20.5	55.4	0
Early Growth	15.0	-2.9	7.9	40.9	39.1	0
Late Growth	15.0	-2.9	7.9	17.1	46.2	16.6
High Growth	13.4	-2.6	7.1	36.5	41.1	14.8

Peaks

Forecasted peak demand is growing at a higher rate than energy demand. This is due to electric vehicle and building electrification demand primarily. As mentioned earlier, in the frozen-efficiency demand forecast, electric vehicles present a relatively unmanaged charge. In this situation, electric vehicle demand generally peaks in the late afternoon/early evening time, which is often also when the system peak occurs. Building electrification demand often peaks in the morning and evening times due to space heating requirements, which also contributes to peaks in those futures with high building electrification.

Historically, the region's peak demand has always occurred in the winter season. However, in the forecast, summer peak events are starting to appear. For example, in the future of Mixed Bag Climate A, 40% of the annual peak events are in the summer. This move to more summer peak events is due to warmer future temperatures, higher building cooling saturations, and more electric vehicles.

Figure F - 44: Regional Annual Peaks



When looking at the forecasted coincident peak across all the future economic conditions and weather patterns, a few aspects are clear. Forecasted data center energy growth is contributing to the peaks, especially early in the forecast period. Even though the data center hourly load pattern is modeled to be fairly level, the energy growth acts as a rising floor for the system peaks. Later in the horizon, electric vehicle charging is driving much of the forecasted peak growth. Potential building electrification in the residential and commercial sectors also begins to drive peak demand, though not to the degree of EV charging. Table F - 14 summarizes the contribution to the coincident peak from the residential/commercial/industrial sectors, data centers, and electric vehicles across all the futures. In these categories, the electric vehicle demand is separated from the residential and commercial sectors, while building electrification is kept in those sectors.

Table F - 14: Demand Contribution on System Peak (MW), Averaged Across All Futures

Year	Total	Res/Com/Ind	Data Center	Electric Vehicles
2027	37,464	35,727	1,600	137
2028	36,081	33,507	2,360	213
2029	37,594	34,030	2,809	755
2030	38,033	34,192	3,086	755

Year	Total	Res/Com/Ind	Data Center	Electric Vehicles
2031	39,292	35,629	3,060	604
2032	38,551	32,973	3,286	2,291
2033	42,487	36,852	3,284	2,350
2034	41,578	35,535	3,437	2,606
2035	41,295	34,356	3,381	3,558
2036	43,511	35,475	3,535	4,500
2037	46,950	38,728	3,585	4,637
2038	47,083	38,506	3,518	5,059
2039	47,616	37,280	3,664	6,672
2040	47,156	36,219	3,753	7,184
2041	50,535	38,874	3,783	7,878
2042	50,309	37,907	3,837	8,565
2043	48,889	35,881	3,913	9,095
2044	51,061	37,691	3,961	9,409
2045	53,880	39,467	4,033	10,380
2046	52,499	37,534	4,009	10,956

Table F - 15 displays the percentage of the coincident system peak that each demand category contributes. As before, this is the average contribution across all futures.

Table F - 15: Average Percent of Peak Contribution Across All Futures

Year	Res/Com/Ind	Data Center	Electric Vehicles
2027	95.4	4.2	0.4
2028	93.0	6.4	0.6
2029	90.7	7.3	2.0
2030	90.0	7.9	2.0
2031	90.9	7.6	1.5
2032	85.7	8.3	6.0
2033	86.6	7.6	5.8
2034	85.5	8.1	6.4
2035	83.3	8.0	8.7

Year	Res/Com/Ind	Data Center	Electric Vehicles
2036	81.7	7.9	10.4
2037	82.4	7.5	10.2
2038	81.7	7.3	10.9
2039	78.4	7.5	14.1
2040	77.0	7.7	15.3
2041	77.0	7.3	15.7
2042	75.5	7.4	17.1
2043	73.5	7.8	18.7
2044	73.9	7.5	18.5
2045	73.4	7.3	19.3
2046	71.6	7.4	21.0

Sales Forecast

The final forecast output, or the "sales forecast," represents the forecasted future loads after accounting for the cost-effective amount of demand side resources as described in Chapter 4, Action Item RES-1.

Conservation and voltage regulation, as outlined in the resource strategy, reduces hourly load throughout the day. Demand response does not reduce overall demand, but instead shifts electricity use to a different time. In the case of electric vehicles, demand response shifts vehicle charging from late afternoon and evening to the early morning hours.

The estimate of the conservation, demand response, and voltage regulation across the entire planning horizon was applied to the frozen-efficiency load forecast. Conservation and voltage regulation reduce demand in the residential, commercial, and industrial sectors. Demand response shifts the load pattern in the residential and commercial sectors, and particularly the electric vehicle demand.

The resulting peak and energy sales forecast for the region is shown in Figure F - 45. This includes all the forecast futures. Figure F - 46 and Figure F - 47 break out the energy (aMW) and peak (MW) forecast individually and includes the frozen-efficiency forecast as a comparison. Figure F - 48 summarizes the percent load reduction to the frozen-efficiency forecast that the conservation and demand response provides. Generally, the peak hour reduction is higher in terms of percentage than the annual energy reduction, due to demand response shifting electric vehicles charging away from typical peak hours.

Figure F - 45: Regional Annual Sales Forecast

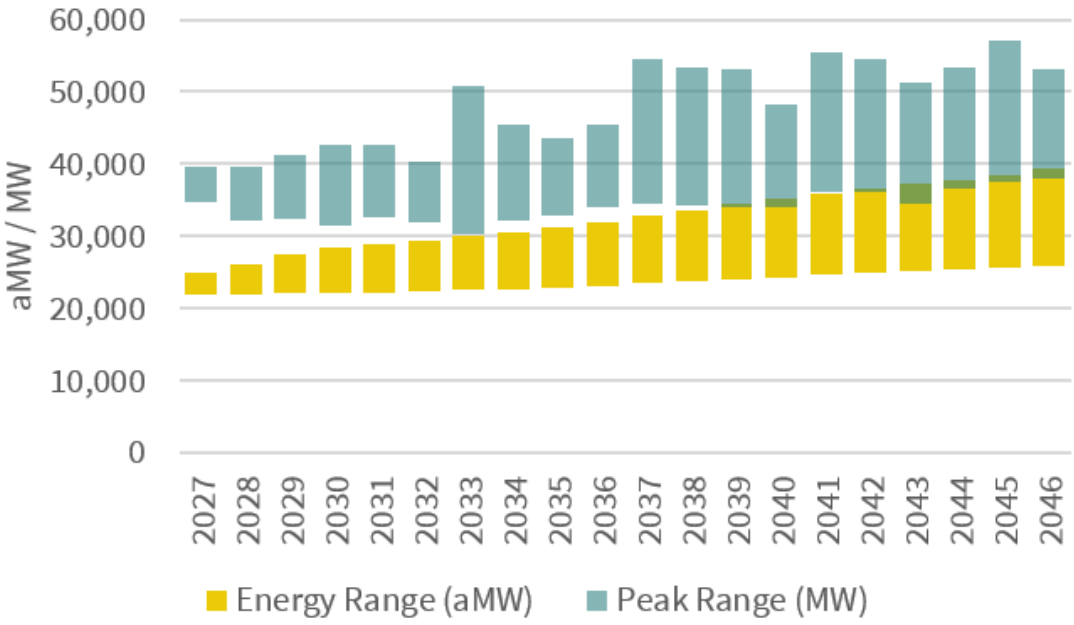


Figure F - 46: Regional Annual Energy Forecast

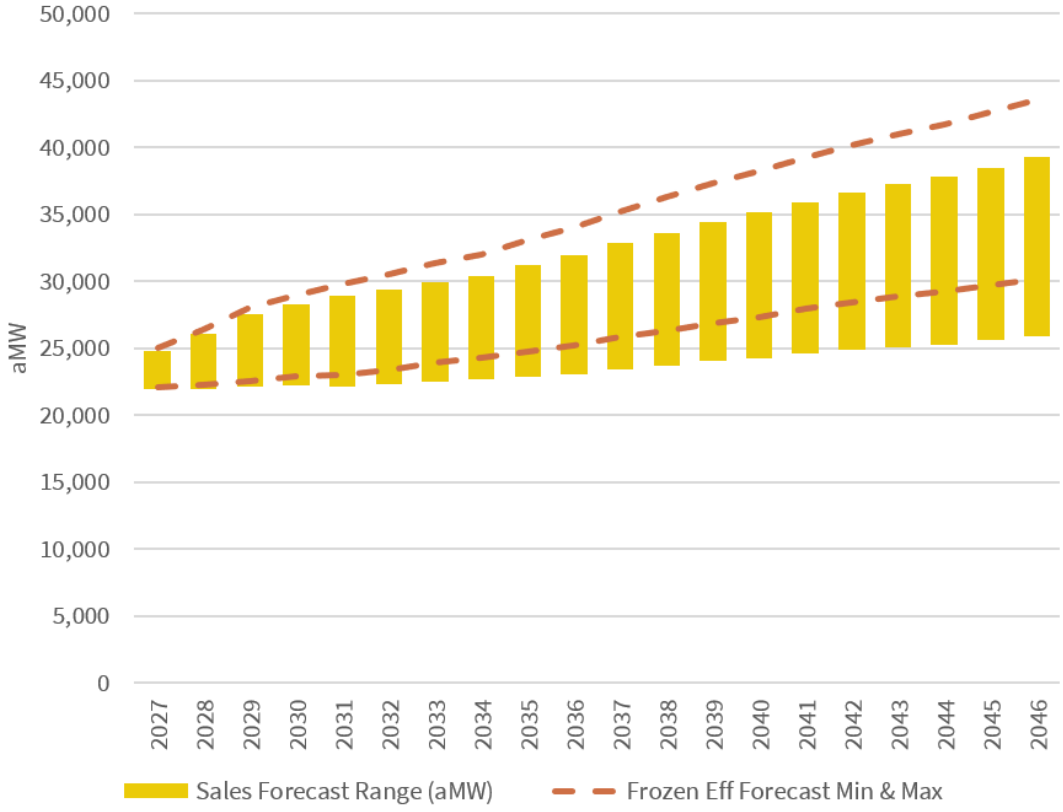
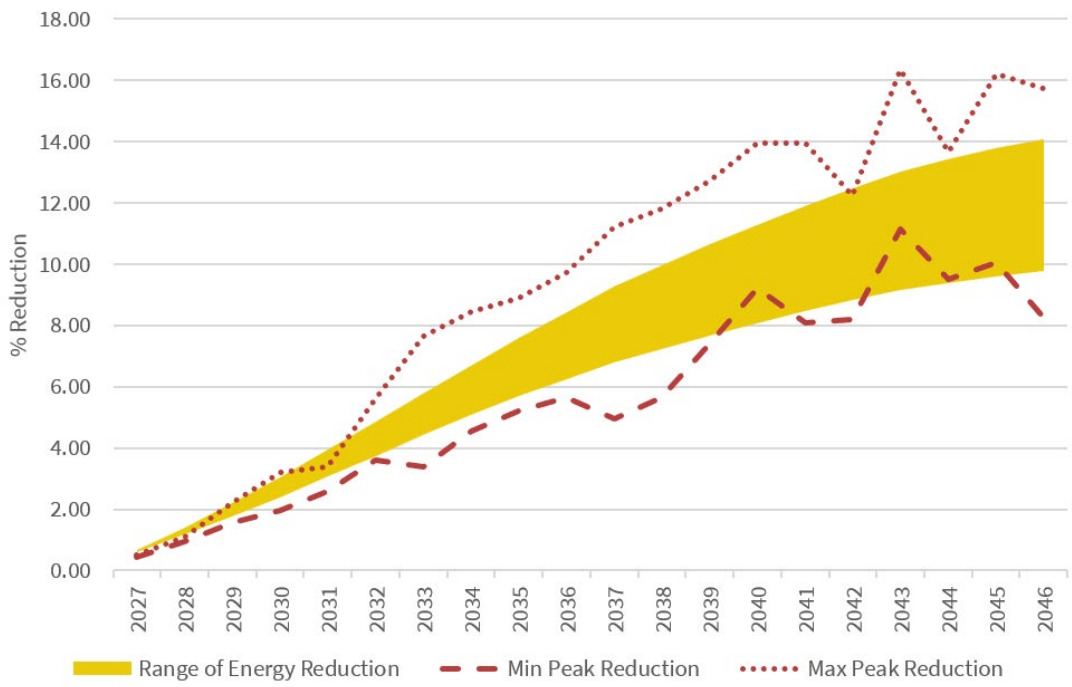


Figure F - 47: Regional Annual Peak Forecast

Figure F - 48: Regional Load Reduction Percentage



Technical Appendix G: New Generating Resources

Contents

Methodology for Assessing New Generating Resource Technology Options for the Power Plan 2
- What is a Reference Plant? 2
- How are Reference Plants Used in Planning? 3

Components of a Generic Reference Plant 3
- Methodology for Defining Reference Plant Components 4
- Shared Assumptions 6
- New Resource Options 17
- Final Suite of Reference Plants 19

Primary Resources 19
- Onshore Wind 20
- Utility-Scale Solar 28
- Small-Scale Solar 47
- Lithium-Ion Battery 52
- Solar Plus Battery 56
- Natural Gas 60

Limited Availability Resources 73
- Conventional Geothermal 73
- Offshore Wind 77
- Pumped Storage 81

Emerging Resources 84
- Proxy Reference Plant Approach 84
- Shared Emerging Technology Assumptions 85
- Clean Baseload 87
- Clean Long Duration Storage 92
- Clean Peaker with Medium Duration Storage 97

Levelized Cost of Energy 102

MicroFin 103
Uncertainty 104

Methodology for Assessing New Generating Resource Technology Options for the Power Plan

Identifying and analyzing new generating resources is a key step in developing a cost-effective, least-risk, adequate, and reliable strategy for the region. Generating resource technologies are defined and assessed based on their cost, operating and performance characteristics, and development potential in the region. Resources that are proven and commercially available to meet future needs are further developed into "reference plants." Each reference plant has a designated plant size and configuration representative for the Pacific Northwest,[1] with technical characteristics and performance parameters, cost estimates (capital, operating and maintenance, levelized), and other attributes such as estimated construction time and economic life. These reference plants become inputs to the Council's optimization models (e.g., OptGen) as options, along with rooftop solar, energy efficiency, and demand response, for selection to meet future resource needs.

For the Ninth Plan, utility-scale reference plants were developed for onshore wind, solar photovoltaics (PV), standalone battery storage, solar PV + battery storage, natural gas combined cycle turbine, and natural gas simple cycle combustion turbines (peaking plants, or "peakers"). The Council also developed reference plants for resources with limited availability including pumped storage, conventional geothermal, and offshore wind and three proxy emerging technology reference plants. These emerging technology reference plants are intended to represent the potential technological advancements that could provide value to the region in the future, and include clean long-duration storage (iron-air battery), clean baseload resource (small modular reactor), and clean peaker/medium-duration storage (hydrogen turbine with onsite production/storage).

What is a Reference Plant?

A reference plant describes an electricity generating resource technology and its theoretical application in the region. It includes estimates of typical costs, logistics, and operating specifications. These reference plants become resource options, along with demand-side resources for the Council's power system models to select to fulfill future resource needs. The Council develops a defined set of reference plants that represent the range of resources to be considered in planning.

[1] These reference plants are also used in the Council's analysis of west-wide market buildouts, some assumptions around the plant characteristics are updated accordingly to better suit the larger west.

How are Reference Plants Used in Planning?

The Power Act directs the Council's power plan to put forth a general strategy for implementing conservation measures and developing generating resources.[2] The Council uses reference plants as a means of characterizing generating resource options for modeling, because they represent the different attributes of different resources for the model to consider.

Components of a Generic Reference Plant

Each reference plant is made up of the components summarized in Table G - 1, defined for each resource. Having the same collection of characteristics differentiated by resource allows the model to best compare and determine the appropriate resource mix.

Table G - 1: Reference Plant Components

Components	Definition
***Resource Attributes*: Defines how a generating technology serves the grid.**	
Technology Type	The type of technology being defined (e.g. a renewable resource, a thermal plant).
Configuration	The number of units (and installed nameplate capacity of each unit) that make up the complete reference plant. Also includes other plant specifications such as air emissions controls, cooling etc.
Capacity	Refers to the nameplate capacity of a plant, which is the maximum amount of electricity a plant can generate when it's fully functional, in optimal conditions, and, if applicable, using the maximum amount of fuel. This is often the manufacturer's rated output of the generator.
Economic or Operating Life	Assumed useful operating life of the plant.
Timing	Includes both *construction time*, which is the amount of assumed time for a project to come online from conception to commissioning, and the *availability date*, or the first year a plant could be selected to be built.
Transmission Access	Assumed transmission required to connect to the grid.
***Financials*: Details what a resource costs, the component parts of those costs, and how those costs are accumulated and recouped over the course of a resource's lifetime.**	
Overnight Capital Cost	An estimate of the project development and construction cost. "Overnight" refers to what the cost would be if the plant were built instantly, or over one night. This cost constitutes the engineering, procurement, and construction (EPC) costs, owner's costs (costs incurred by the project developer – permits, licenses, land, project

[2] Northwest Power Act, §4(e)(2), 94 Stat. 2706

Components	Definition
	development costs, infrastructure, taxes, regulatory compliance costs, etc.), and decommissioning costs.
Fixed Operations & Maintenance	An estimate of the fixed operation and maintenance cost for the reference plant, including operating and maintenance, labor and materials, and administrative overhead. Both routine maintenance and major maintenance and capital replacement are assumed to be included.
Variable Operations & Maintenance	An estimate of the variable operation and maintenance cost for the reference plant, including all costs that are a function of the amount of power produced. This includes consumables such as water, chemicals, lubricants, catalysts, and waste disposal.
Fixed Fuel Cost	The primary type of fuel burned (natural gas, oil, coal, etc.), its location of origin, and cost.
Transmission Cost	Cost of the assumed transmission type, incorporated into the cost of the resource.
***Operating Characteristics*: Describes how the generating technology works.**	
Capacity Factor	An estimate of the ratio of actual annual output to nameplate capacity can vary by location especially for renewables.
Heat Rate	A measure of the efficiency of which a generator converts fuel into electricity. The reference plant heat rates are based on full load, expressed as higher heating values (HHV).
Generation Shape	Refers to when a plant generates power and how much it generates, which can vary by time of day, time of year, location etc.
***Developmental Potential*: Identifies how the generating resource fits into the grid & works with other resources.**	
Location	The general geographic location of the reference plant, which is important in properly accounting for plant attributes (e.g. capacity factor, transmission access).
Transmission/Gas Pipeline Access	A resources available access to necessary infrastructure for it to come online and serve load.
Maximum Build-out	The maximum amount of reference plant units (in megawatts) that the model can select over the 20-year planning horizon.

Methodology for Defining Reference Plant Components

The process of detailing each reference plant and defining their characteristics by technology began with research, looking at manufacturer data, power purchase agreements (PPAs), project-specific publicly available specs, technical handbooks, reports from US Energy Information Association (EIA), Department of Energy (DOE), national labs, and regional integrated resource plans (IRPs) to gather a broad range of data points to be compared and vetted by the regional experts on relevant advisory committees. How those characteristics were defined for each resource and with what level of granularity was dependent on the sort of data available, some of those nuances in process are outlined below. The specifics like the costs of each resource, the resources availability, the timing and

their generation shape, to name a few of the most impactful assumptions, will be detailed by resource in the sections to come, the intent of this section is to describe the development of those characteristics and how they will be presented in the reference plant.

Availability

Availability refers to when and where a resource can be selected by the model and how much of the resource will be available. This includes a resource's earliest selection date as well as how long it takes that resource to be developed and start providing energy to the grid. It also refers to how much energy a single reference plant is sized to produce, its nameplate capacity, as well has how efficiently it provides that electricity to the grid. This could be identified by a resource's capacity factor, heat rate round trip efficiency, or other factors, depending on the resource.

The way resources are selected is another piece of their availability. Resources that are more commutable or scalable can be selected continuously. For example, the wind resource in a particular zone can be any size, so long as there's space on the grid to deliver it, because it's just a matter of adding another turbine. The same holds true for solar and batteries. However, some resources don't operate as modularly, so they are ascribed a discrete size. A gas plant operates a specific turbine that produces a specific amount of electricity. Similarly, pumped storage, geothermal, and hydrogen plants are all a defined size in the model, because they produce a discrete amount of energy by plant. This differentiation is determined by the type of resource and described in the applicable resource's sections.

Primary resources are all available at the beginning of the study, because they're proven, deployable, commercially available and significant. Some limited availability resources aren't selectable right away due to complications of siting and licensing that come up when trying to build a resource with constrained geographic applications. Emerging technologies are not available at the beginning of the study, and the specifics of their availability are based on advisory committee assumptions about the timing of the proxy technologies' commercial readiness.

A final aspect of availability is the location of the resource. This is not relevant for all resources but for some it's especially important. The model will not select a resource in a place it wouldn't realistically be built. For example, it can't build a wind farm in downtown Seattle. New modeling capabilities for the Ninth Plan allow for more granularity in resource selection by zone, making identifying and defining any locational variation more impactful. A resource's cost, operating characteristics, and size can be affected by where it is located. This is especially relevant for renewables, because the natural resource they're capturing and converting into electricity differs across the region. When and how much the sun shines differs for a solar panel in Idaho compared with the Willamette Valley. The reference plant descriptions specify the details of this variability and how locations were decided.

Costs

The process for developing these financial parameters involves gathering analysis of available cost data from manufacturers, developers, PPAs, project-specific publicly available reported information, technical handbooks, reports from the EIA, DOE, national labs, and IRPs, among other sources. Next,

the cost data is normalized to a consistent year dollar, configuration, capacity, and heat rate, among other factors. Finally, that normalized data is plotted to look for trends and outliers to determine the best estimate of current and future costs. Plots for overnight capital costs as well as operations and maintenance costs will be included in each reference plant description.

Environmental Costs

The Northwest Power Act requires that the Council compare the incremental system costs of different generating and conservation resources and give priority to those resources which the Council determines to be cost-effective[3]. For supply side resources, those costs are developed using the method described above. In addition to those financial costs, the Council also includes any quantifiable environmental costs and benefits directly attributed to that resource over its effective life. This is done through the development of a methodology to determine and apply these quantifiable environmental costs and benefits. This methodology's development and implementation are a required element of the power plan and is described in more detail in Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits.[4]

The Act also requires that in developing the power plan's resource strategy that the Council give "due consideration" to environmental quality and fish and wildlife concerns.[5] These are broader considerations than fit within the methodology for quantifying environmental costs and benefits, and include the Council's Fish and Wildlife Program, compliance with clean energy regulations, climate model analysis etc. The environmental effects of supply-side generating resources are discussed narratively in Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits, and while not quantified into monetary costs, can still be considered in the selection of resources and the development of the Council's resource strategy.

Shared Assumptions

There are several assumptions made early in the reference plant development process that are used across all the reference plants to ensure consistency and enable comparison across resources.

Financing

Table G - 2 summarizes the shared financial assumptions.

[3] Northwest Power Act, Section 4(e)(1).
[4] Northwest Power Act, Section 4(e)(3)(C).
[5] Northwest Power Act, §4(e)(2), 94 Stat. 2706

Table G - 2: Financial Assumptions for Reference Plants

Parameters	Ninth Plan Assumption		
Federal income tax rate	21%		
State income tax rate	6.45%		
Property tax	0.9%		
Insurance	0.3%		
	Utility	**Merchant/IPP**	**9P Assumption**
Debt fraction	50/50	55/45	52/48
Debt interest rate (nominal)	3.5%	6.27%	4.61%
Return on equity (nominal)	7.17%	9.74%	8.20%

It's important to consider how resources are financed – as well as by whom – when comparing their present value across resources. In the Ninth Plan, a blend of utility and merchant financing was assumed at a ratio of 60 percent utility financed 40 percent merchant/independent power producers. This assumption is based on who is building power plants nationally as informed by EPA's power sector modeling, which is used by the EIA to produce their annual energy outlook report.[6]

These assumptions are built into the Council's financial revenue requirements model. They are used to calculate the levelized fixed costs of supply-side resources, which are compared against each other as well as demand-side resources in modeling. More information on how these financing assumptions compare to demand-side financing can be found Technical Appendix A –Global Assumptions.

Transmission

There are costs associated with connecting a resource to the grid via electric transmission. To get their generation onto the grid, a resource must acquire transmission access often via contract with a transmission operator. Bonneville Power Administration (BPA) operates 75% of the region's high-voltage transmission system. The Council looked to the agency's most recent transmission tariff as a proxy for all transmission costs. This can be a nuanced calculation dependent on the individual circumstances of the resource being connected. However, the Council opted to use BPA's long-term firm point-to-point (PTP) transmission service rate as a surrogate for all transmission costs, because it is the most straightforward, reliable transmission option. BPA's 2024 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions set the long-term firm

[6] Documentation of financing assumptions for EPA's power sector modeling are available at https://www.epa.gov/system/files/documents/2021-09/chapter-10-financial-assumptions.pdf.

PTP rate at $1.64/kW-mo, which works out to $19.76/kW-yr.[7] This is incorporated into a resource's fixed costs in addition to any other annual operation and maintenance expenses. It is added to the fixed O&M of every resource that connects to the transmission system. The only resources that are excluded are small-scale solar, which operate on the distribution system, as well as batteries, because they're on-system resources that do not require dedicated transmission capacity.

These costs do not include wheeling costs, which are tied to usage of the line and not to a particular resource. Wheeling costs are contractual, variable costs that are associated with transmitting power. They are added up per wheeling segment traveled, and are accounted for in the model per megawatt hour.

Maximum Buildout

For the Ninth Plan, the Council is not limiting primary model resource builds beyond the physical constraints of the system. This approach relies on the model to test the economics of a given future, not being constrained by contractual encumberments. The future will be constrained by system operations and policies, among other factors. The Council recognizes that there might be limits on various resources from siting or supply chain limitations (e.g. transformers). The implications of such limitations will be explored through the Resource and Transmission Risk Scenario, which is described in more detail later in this appendix.

Cost Curves

Technology improves in both performance and price over time, and the Council relies on cost curves to estimate costs across the 20-year planning period. These learning curves vary based on the maturity of the technology but apply to all technology types. The National Laboratory of the Rockies's Annual Technology Baseline's (NLR ATB)[8,9] cost curves were utilized as a well-supported and documented industry standard. In past power plans the moderate cost curve provided by NLR was used, however, recent industry uncertainty has prompted the Council to adopt the conservative curve for the Ninth Plan Figure G - 1 provides an overview of each cost curve and how they compare across resources. More mature technologies, like natural gas or wind see a slower de-escalation while more recently emergent resources such as solar and batteries see a steeper decline, especially in the near term. This follows the logic of exponential learning curves where increased production prompts cheaper costs due to economies of scale, experience, process improvements etc. In the 20-year horizon of the Plan, these trade-offs between cost and scale are used to predict future costs.

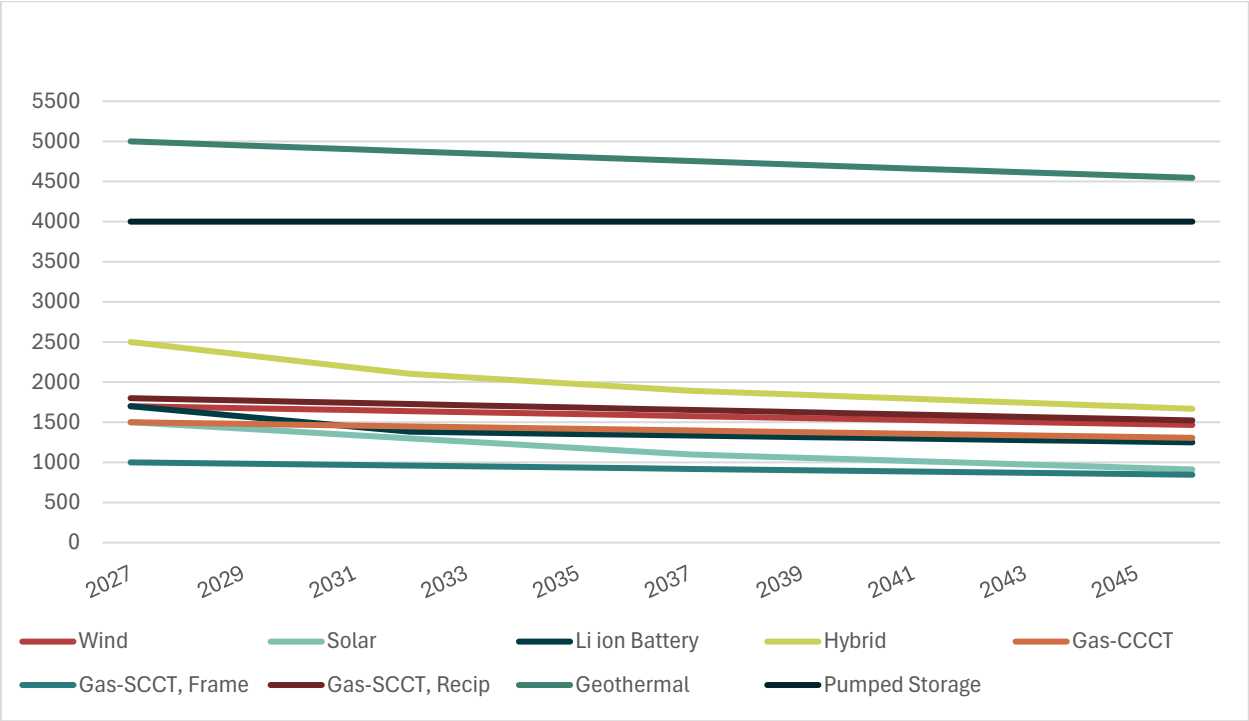
[7] https://www.bpa.gov/-/media/Aep/rates-tariff/current-transmission-rates/2024-Transmission-Rates/2024-Final-Proposal-Transmission-Rate-Schedules-and-GRSPsFERC-approved.pdf.

[8] The National Laboratory of the Rockies is formerly known as the National Renewable Energy Lab or NREL. The name changed in December 2025. The website continues to have an NREL in the URL and many of the resources continue to be cited as NREL resources.

[9] More information on the ATB is available at https://atb.nrel.gov/electricity/2024/data.

In addition to Figure G - 1, cost curves for each resource are broken out and included in each reference plant description throughout the document.

Figure G - 1: Forward Cost Curve for Primary Resource Reference Plants



Locational Cost Adjustment

Locational cost adjustment factors from the 2025 EIA Energy Outlook[10] were applied to resources' overnight capital costs. This adjustment is based on labor rates and the environmental effect on material costs for each location. These factors are specific to each resource and by representative city, but broadly it is more expensive to build in the west of the region (Seattle/Portland) than the east (Spokane/Boise/Great Falls). This adjustment is only made when there are other differentiating factors between resources by location. For example, wind and solar have capacity factors that vary enough by location to warrant separation, and gas plants have distinct fuel costs along the east/west divide. The factors given by location and resource in Table G - 3 are applied in their specific resource reference plant descriptions provided later in this section.

[10] Adjustment factors by resource and location can be found in Appendix A. Labor Location-Based Cost Adjustments of the EIA's Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

Table G - 3: Regional Location-Based Cost Adjustments by Resource

	Solar	Solar+ Battery	Wind	Gas: CCCT	Gas: SSCT
Portland, OR	1.058	1.061	1.108	1.099	1.095
Seattle, WA	1.088	1.088	1.1598	1.152	1.145
Spokane, WA	1.0233	1.0253	1.0376	1.034	1.032
Great Falls, MT	0.992	0.991	0.983	0.984	0.984
Boise, ID	1.009	1.011	1.0229	1.013	1.013
Cheyenne, WY	NA	NA	0.9825	NA	NA

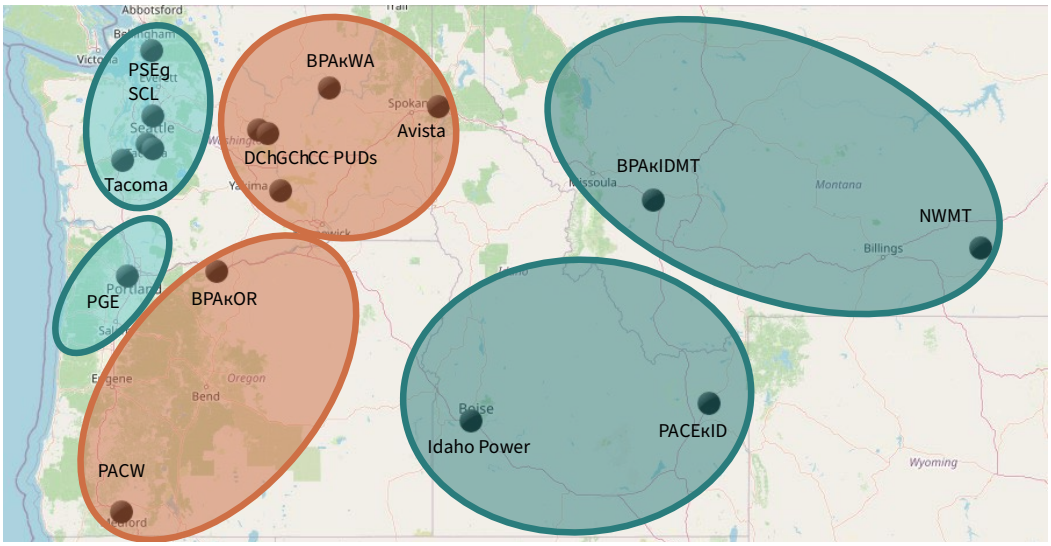
Generation Shape

Weather-dependent resources, primarily wind and solar, are assigned daily and monthly production shapes to represent how that resource produces energy. These shapes vary by location in the region, and the expanded locational granularity of the updated models allow us to better represent those differences. For both wind and solar, representative shapes that apply to broader portions of the region were selected. For example, a solar profile in Portland is very similar to one in Seattle, so both those locations have been assigned the same generation shape. Those locations and the zones they encompass are shown in Table G - 2.

The precise shapes are a separate modeling input,[11] but the maps shown in Figure G - 2 and Figure G - 3 provide a visual representation of those groupings by resource.

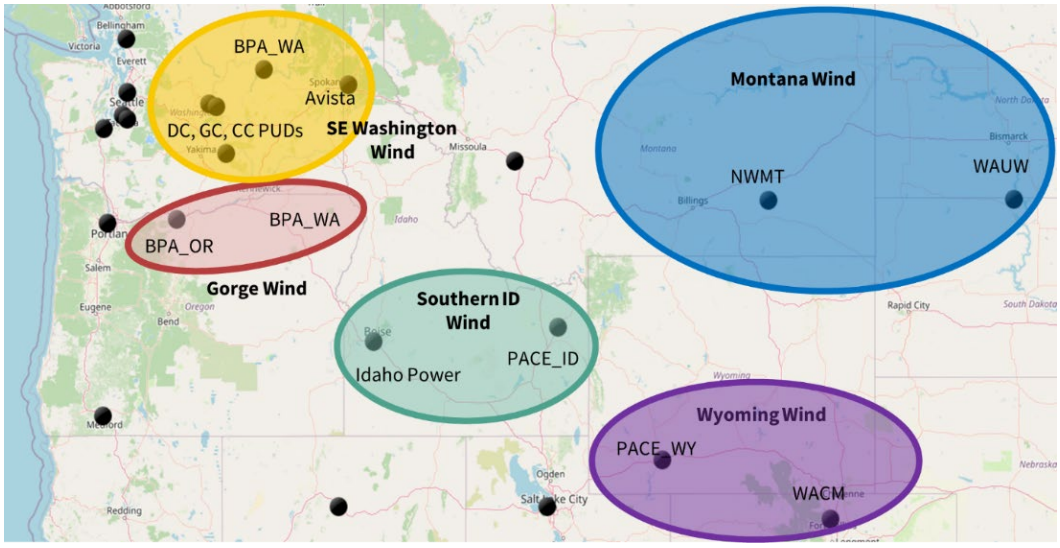
[11] Weather and how it is used to model generation is described in Technical Appendix D – Climate Model Data and Assumptions

Figure G - 2: Solar Reference Plant Locations



The solar shapes in Figure G - 2 are grouped by color and then split by wildfire smoke profiles that will be applied on top of those shared shapes. More details on the grouping of these zones is discussed in the solar reference plant definition section below.

Figure G - 3: Wind Reference Plant Locations



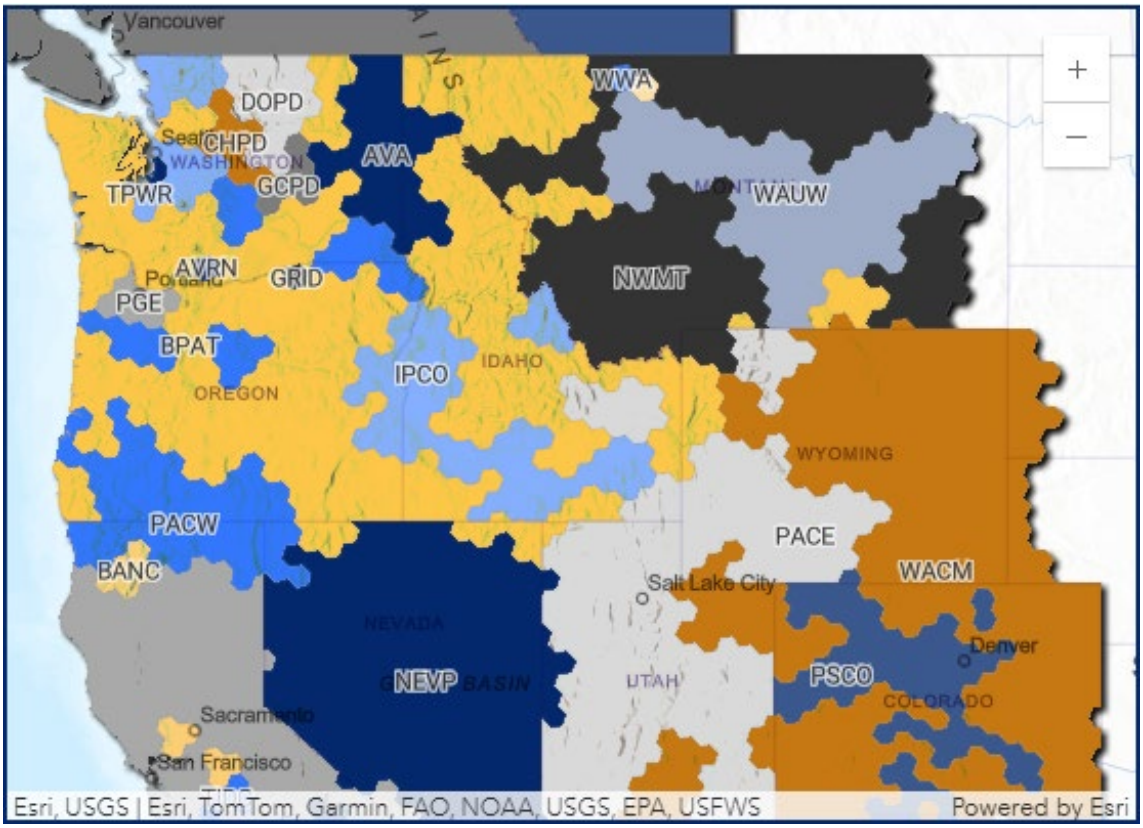
The representative wind shapes cover less of the region, as wind farms have larger footprints and cannot be built as widely as solar can be. The alignment of the zones encompassed by the broader groupings shown in Figure G - 3 are described in more detail in the land-based wind reference plant definition section.

Location assignments by resource by zone

In the Council's models, the region is split into seventeen smaller sub-regions or "modeling zones." The modeling zones correspond approximately to the Northwest's balancing authorities, or portions of its balancing authorities. The Council simplified the model by clustering resources by shared characteristics, described in the two sections above and explained in more detail later in this appendix. The Council deemed it unnecessary to develop 17 different reference plants for every resource, as there are not significant enough identifiable differences in the resource attributes to warrant such granularity. Rather, the Council grouped the zones based on similar characteristics per plant.

summarizes these assignments while Table G - 5 describes the zone abbreviations. These modeling zones roughly align with the balancing authorities mapped in Figure G - 4, to get an idea of the geographic location of the zones.

Figure G - 4 WECC Balancing Authorities Mapped[12]



[12] https://wecc-spdp-weccgeo.hub.arcgis.com/pages/bulk-power#c25n8scx9.

1 **Table G - 4: Modeling Zone Reference Plant Assignments**

Resource Type	Resource Technology	Location Cluster	Zone
Solar[13]	Stand-alone	Northwest	North: N/A South: PGE
		Central	North: BPA WA, AVA, DC PUD, CC PUD, GC PUD South: BPA OR, PAC W
		East	North: BPA IDMT, NWMT South: PAC E ID, IPCO
	Small-Scale	Northwest	North: PSE (North, Central, Olympia) SCL, TPWER South: PGE
		Central	North: BPA WA, AVA, DC PUD, CC PUD, GC PUD South: BPA OR, PAC W
		East	North: BPA IDMT, NWMT South: PAC E ID, IPCO
	Hybrid	Northwest	North: PSE (North, Olympia) SCL, TPWER South: PGE
		Central	North: BPA WA, AVA, DC PUD, CC PUD, GC PUD South: BPA OR, PAC W
		East	North: BPA IDMT, NWMT South: PAC E ID, IPCO
Wind	N/A	Gorge	BPA OR, BPA WA
		SE Washington	BPA WA, AVA, DC PUD, CC PUD, GC PUD
		S Idaho	IPCO, PAC E ID
		Montana	BPA IDMT, NWMT, WAUW
		Wyoming	PAC E WY, WACM
Gas	Combined Cycle	Eastside	IPCO, BPA IDMT, NWMT, AVA
		Westside	PSE Olympia
		BPA Blend[14]	BPA WA

[13] North and south designations refer to the wildfire profile applied to each zone, discussed later in the appendix.
[14] The BPA zone spans the east and west sides and therefore warranted a blended value. This is also consistent with the T&D deferral values.

Resource Type	Resource Technology	Location Cluster	Zone
	Peaker	Eastside	IPCO, BPA IDMT, NWMT, AVA
		Westside	PSE (Central, North, Olympia)
		BPA Blend	BPA WA
Emerging Technology	Clean Baseload	N/A	AVA, BPA IDMT, BPA WA, IPCO, NWMT, PSE Olympia
	Clean Long Duration Energy Storage	N/A	BPA IDMT, NWMT, PAC E ID, IPCO, BPA WA, AVA, DC PUD, CC PUD, GC PUD, BPA OR, PAC W, PSE (North, Central, Olympia) SCL, TPWER, PGE
	Clean Peaker	N/A	BPA IDMT, NWMT, PAC E ID, IPCO, BPA WA, AVA, DC PUD, CC PUD, GC PUD, BPA OR, PAC W, PSE (North, Central, Olympia) SCL, TPWER, PGE

1 **Table G - 5: Modeling Zone Names and Abbreviations**

Modeling Zone Name	Modeling Zone Abbreviation
Avista Utilities	AVA
Bonneville Power Administration, Idaho and Montana	BPA_IDMT
Bonneville Power Administration, Oregon	BPA_OR
Bonneville Power Administration, Washington	BPA_WA
Chelan County PUD	CCPUD
Douglas County PUD	DCPUD
Grant County PUD	GCPUD
Idaho Power Company	IPCO
NorthWestern Energy	NWMT
PacifiCorp, East (Idaho & Wyoming)	PACE
PacifiCorp, West (Oregon & Washington)	PACW
Portland General Electric	PGE
Puget Sound Energy, Central	PSE_Central
Puget Sound Energy, North	PSE_North
Puget Sound Energy, Olympia	PSE_Olympia
Seattle City Light	SCL
Tacoma Power	TPWER
Western Area Power Administration, Colorado-Missouri Region	WACM

Modeling Zone Name	Modeling Zone Abbreviation
Western Area Power Administration, Upper Great Plains West	WAUW

Sources

Many of the attributes being defined for each resource, especially costs, rely on comprehensive literature reviews plotted on a single axis so they can be compared. Some of these sources have data for multiple resources, like NLR's Annual Technology Baseline, while others are more specific, like Gas Turbine World's 2024 handbook. All of the sources relied on for the plotted costs throughout the resource sections below are named in Table G - 6. The table also identifies the applicable resources by source and how it will be abbreviated through the rest of the appendix.

Table G - 6: Data Sources Referred to Throughout Appendix[15]

Source	Resources	Abv.
EIA's Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies[16]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, SMR	(AEO 2025)
LBNL's Land-Based Wind Market Report 2024[17]	Wind	(LBNL 2024)
LBNL's Utility Scale Solar Market Report 2024[18]	Solar, Solar+Storage	(LBNL 2024)
NLR's Annual Technology Baseline[19]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, Offshore Wind, SMR	(ATB 2024)
Lazard's Levelized Cost of Energy+ Ed.17[20]	Wind, Solar, Solar+Storage	(LCOE+ 2024)
PNNL's Energy Storage Grid Challenge Cost and Performance Database[21]	Battery	(ESGC 2024)
Gas Turbine World-2024 Handbook[22]	Natural Gas	(Gas Turbine World)
EIA Annual Energy Output 2023[23]	SMR	(AEO23 EIA)

[15] All sources and a detailed look at how they were used by resource can be found compiled here: https://nwcouncil.box.com/v/9thPlanRefPlantCosts.
[16] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.
[17] https://emp.lbl.gov/wind-technologies-market-report.
[18] https://emp.lbl.gov/publications/utility-scale-solar-2024-edition.
[19] https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.
[20] https://www.lazard.com/research-insights/levelized-cost-of-energyplus.
[21] https://www.pnnl.gov/projects/esgc-cost-performance/download-reports.
[22] https://gasturbineworld.zinioapps.com/publications/gas-turbine-world-handbook/42029/issues/658295.
[23] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

Source	Resources	Abv.
NLR/DOE Techno-Economic Analysis[24]	H2	(NLR/DOE Techno-Econ Analysis)
E3 Western Long Term Market Potential[25]	H2	(E3 Western Market Potential)
NLR H2@ Scale report[26]	H2	(NLR H2@ Scale)
PNNL 2020 Grid Energy Storage Tech Cost and Performance Assessment[27]	H2	(PNNL 2020)
DOE Hydrogen Program Record[28]	H2	(DOE Hydrogen Program Record)
Form Energy Correspondence[29]	FE Air	(Form E)
PGE 2023 Integrated Resource Plan [30]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, Offshore Wind, SMR, H2	(PGE 2023)
PacifiCorp 2025 Draft Integrated Resource Plan[31]	Wind, Solar, Battery, Natural Gas, Pumped Hydro, Offshore Wind, SMR, H2, Fe Air	(PAC 2025)
PacifiCorp 2023 Integrated Resource Plan[32]	Conv. Geothermal, H2	(PAC 2023)
Idaho Power 2023 Integrated Resource Plan[33]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, SMR, H2, Fe Air	(ID Power 2023)
Avista 2025 Integrated Resource Plan[34]	Wind, Solar, Battery, Natural Gas, Pumped Hydro, Offshore Wind, SMR, H2, Fe Air	(Avista 2025)

[24] https://www.cell.com/joule/fulltext/S2542-4351(21)00306-8.
[25] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf.
[26] https://docs.nrel.gov/docs/fy21osti/77610.pdf.
[27] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf.
[28] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/24005-clean-hydrogen-production-cost-pem-electrolyzer.pdf.
[29] https://formenergy.com.
[30] https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp.
[31] https://www.pacificorp.com/energy/integrated-resource-plan.html
[32] Ibid
[33] https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan.
[34] https://www.myavista.com/about-us/integrated-resource-planning.

Source	Resources	Abv.
Puget Sound Energy 2023 Integrated Resource Plan Progress Report[35]	Wind, Solar, Battery, Natural Gas, Pumped Hydro, Offshore Wind, SMR	(PSE 2023)
NorthWestern 2023 Integrated Resource Plan[36]	Natural Gas	(NWestern 2023)

New Resource Options

The Council considers a wide range of resource options in developing a power plan. Table G - 7 includes a list of all generating resources considered in the Ninth Plan.

Table G - 7: Resources Considered

Primary	Limited Availability	Emerging
Utility Scale Solar PV	Conventional Geothermal	Enhanced Geothermal
Onshore Wind	Offshore Wind	Small Modular Reactors
Small Scale Renewables	Pumped Storage	Carbon Capture & Sequestration
Gas CCCT	Biomass	Hydrogen Gas Turbine
Gas SCCT – Frame	Hydro Upgrades	Allam Cycle Gas
Gas SCCT – Reciprocating Engine	Biogas	Wave, Tidal
Gas SCCT – Aeroderivative	Small Hydro	Long Duration Storage
Battery Storage (Li-ion)	Combined Heat & Power	
Renewables + Storage		

This list was pared down with the help of regional experts and advisory committee feedback, and compiled into a final list of resources. The final list was developed into reference plants and fed into the model. The goal is a streamlined list that still represents the full breadth of resource options available to the region.

The Council mostly did not develop full reference plants for resources with limited, or small-scale, developmental potential in the Pacific Northwest. In some instances, the Council selected one technology type over other similar options, such as single gas peaker technology or a specific renewable resource to pair with storage. In other cases, the resource is not being built in the region,

[35] https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.
[36] https://northwesternenergy.com/about-us/gas-electric/montana-electric-supply-planning/montana-integrated-resource-plan-2023.

like biomass or small hydro. The resources that were precluded from reference plant development are described with some detail below. While these resources are not explicitly modeled, they are still considered viable resource options for future power planning needs.

The treatment of emerging resources, the red column in Table G - 7, is described later in this appendix.

Aeroderivative Turbines

Aeroderivative turbines are a type of simple cycle gas turbine technology. They are characterized by their light weight, highly efficient, and flexible design. When selecting which gas turbine technology to include in the Ninth Plan, reciprocating engines and frame turbines were chosen as the representative gas peaker technologies. Aeroderivative turbines are less commonly built in the region and are more expensive and less modularly flexible than the frame turbines or reciprocating engines.

Renewables Plus Storage

While solar is the most common renewable paired with batteries, it is not the only resource that can be co-located with storage. Wind + storage and a wind + solar + storage resource were both considered in the resource selection process. These pairings are not yet common practice in the region, likely because wind generation is less consistent than solar production (which has a similar shape every day), therefore resulting in a less reliable pair for shorter duration storage. Ultimately, the Council decided to just develop a reference plant for solar + storage.

Biomass and Biogas

Biomass refers to an organic material that can be converted to energy through direct combustion or converted into gaseous or liquid fuels. In the region, much of the biomass capacity is fueled by burning spent pulping liquor and woody residues from the logging/paper industry. Biological conversion of biomass produces biogas through the anaerobic digestion of organic materials, like food waste, manure etc., resulting in a gaseous mixture that can be combusted like natural gas. While biomass is utilized for electricity production in the region, it is not a common fuel choice. However, in some planning it is being looked at as a potential 'renewable' alternative to other combustibles. The Council opted to not develop a reference plant for the resource based on this limited regional use.

Hydro Upgrades and Small Hydro

Hydropower upgrades increase existing capacity by replacing or improving turbines, generators, etc. and small hydro refers to small turbines that can capture energy from irrigation infrastructure, low-head stream flows, water treatment plant outfalls etc. with a smaller footprint or impact on the surrounding environment than a traditional hydroelectric dam. These technologies are highly site specific and not often utilized at scale in the region. This minimal development led the Council to not develop a reference plant for these technologies.

Combined Heat and Power

Combined heat and power plants produce electricity and another useful thermal energy (heat, steam) that is more efficient than if both sources of energy were to be produced separately. These are most often used in industrial applications to make more efficient use of process heat. These tend to be closed systems, where the industrial plant utilizes the process heat to produce electricity which it then uses in its own operations, rather than serving the larger grid. Many of the industries that deployed cogeneration - like paper and aluminum- have left the region, making it a less viable new resource option.[37] The Council concluded a reference plant for the technology wasn't needed.

Final Suite of Reference Plants

After deliberating on the full suite of resource options in Table G - 7, the Council landed on a reduced list to use as reference plants. Table G - 8 provides the final list of resources for which the Council developed reference plants for inclusion in the modeling.

Table G - 8: Final Resource Selection

Primary	Limited Availability	Emerging
Utility Scale Solar PV	Conventional Geothermal	Clean Long-Duration Storage Proxy
Onshore Wind	Offshore Wind	Clean Baseload Proxy
Small Scale Solar	Pumped Storage	Clean Peaker/Medium-Duration Storage Proxy
Gas (CCCT, SCCT – Frame/ – Reciprocating Engine)		
Battery Storage (Li-ion)		
Solar + Storage		

Primary Resources

Generating resources that are deemed proven, commercially available, and deployable on a large scale in the region at the start of the study period are Primary Resources. These resources have the potential to play a major role in the future regional power system. To ensure a deep understanding of these resources and their potential, the Council performs an in-depth, quantitative characterization.

[37] The Power Act (Northwest Power Act, §4(e)(1), 94 Stat. 2705) gives priority to first, conservation, second, renewable resources, and third generating resources utilizing waste heat. Industrial cogen falls under this third priority category. It was considered but not developed further into a full reference plant for the above describe reasons.

Onshore Wind

Wind power is a naturally occurring, renewable form of energy that is harnessed and transferred into electricity through power plants made up of individual turbines. Wind turbines primarily consist of a tower, two or three blades, hub and rotor, and a nacelle (consisting of interconnected low and high-speed shafts, a gear box, and a generator). As the wind blows, the turbine blades (connected at the hub and attached to the rotor) are rotated, with the rotor causing the low-speed shaft to spin within the nacelle. Housed in the gearbox, the low-speed shaft is connected to the high-speed shaft, which increases the speed of the rotation. The gearbox is attached to the generator, which produces electricity. Wind turbines typically possess weathervanes and anemometers (an instrument to measure wind speed) that transfer information to a controller. Between the controller computer system and remote operators, a wind turbine can be turned on and off depending on the wind speed as well as positioned depending on the wind direction.

For more information about wind development in the region see Technical Appendix B – Existing System Parameters and Policies.

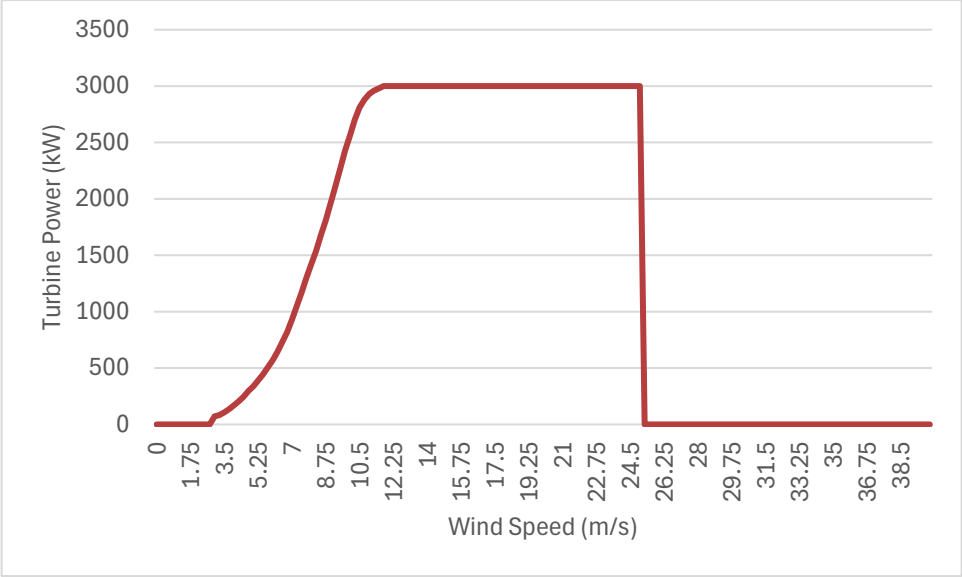
Availability

Onshore wind is available to be built at the beginning of the study period and takes 3 years for development and construction. There are potentially some limiting factors to account for when considering the development of wind, such as siting constraints, available land and community pushback, and supply constraints especially with uncertainty around tariffs and transformer supply. Some of the land considerations are factored in when selecting the wind locations, discussed in detail below. Most land consideration limits are thought to be fairly universal across resources and will be tested in scenario analysis, the specifics of which are described in a later section.

Wind is one resource that the model can select continuously, so there isn't a plant size consideration to be made. However, a specific turbine type had to be selected for the modeling of wind generation over the course of the study. This required considering recent turbine types being used in the region,[38] with some concessions made for available data. Power curves of turbines currently in production are often proprietary. The turbine model chosen for the Ninth Plan representative wind resource is the Vestas v112-30, whose power curve is illustrated in Figure G - 5. The power curve shows the turbine's electric power output by wind speed. How this turbine performance is then processed into wind generation is described in Technical Appendix D – Climate Model Data and Assumptions.

[38] File 3_2_Wind2024: https://www.eia.gov/electricity/data/eia860.

Figure G - 5: Turbine Power Curve[39]



Location

Wind resources vary across the region. The Council's goal in evaluating the differences in generation required balancing computing and analytical workload with the value of the insights gained into the variability of the region's wind resource. Combining all wind resources in the region into a single capacity factor would be over-generalizing, and result in inaccurate data. Modeling precise wind regimes in every modeling zone would be too granular.

The Council compiled annual wind generation at different weather stations across the region into five differentiable zones. Wind generation in the Columbia River Gorge is different from Southeast Washington, which was distinct from Southern Idaho. The analysis also captured different capacities in Montana and Wyoming. These zones nicely mapped to where, historically, wind plants have been built in the region, further supporting the choice.

These zones and historical builds are shown in

Figure G - 6. After selecting these locations as representative of the region, synthetic future generation curves, like those shown in Figure G - 7, were generated for every hour of every day for each location for the whole study. More on this development process is detailed in Technical Appendix D – Climate Model Data and Assumptions.

[39] https://samrepo.nrelcloud.org/help/wind_turbine.html.

Figure G - 6: Existing Regional Wind Clusters Mapped

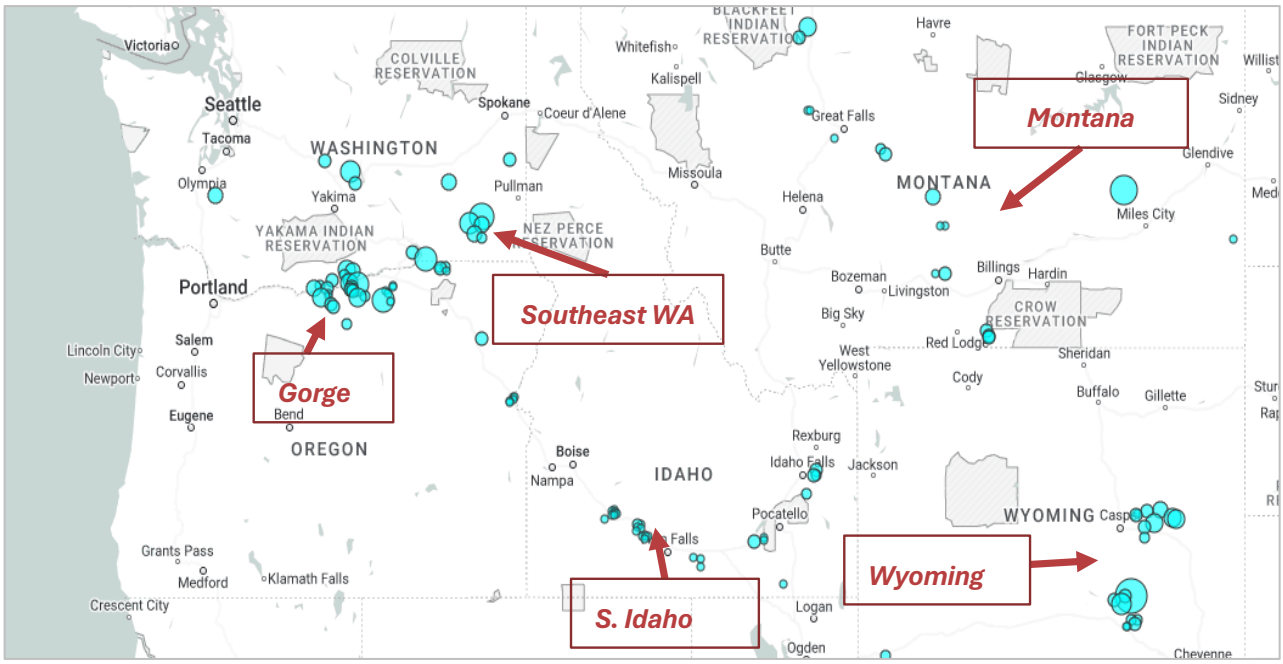
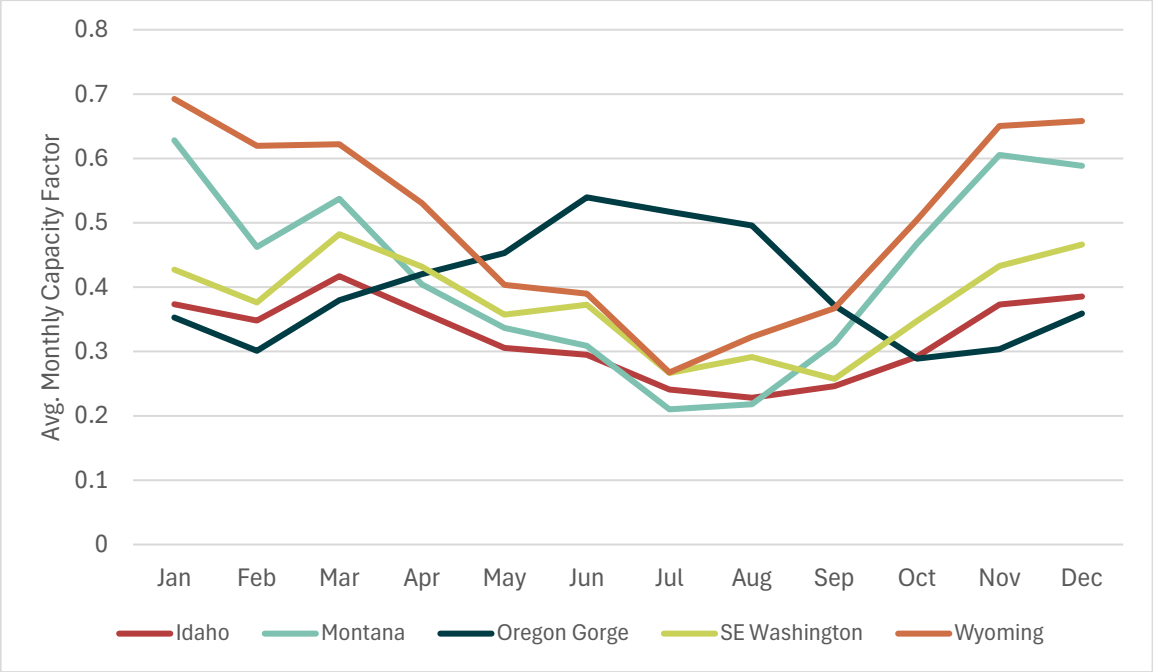


Figure G - 7: Average Monthly Capacity Factors Across Regional Wind Generation Clusters



Out of Region Wind Locations

The broader WECC is modeled in the plan development process to inform wholesale market availability. To forecast this market availability the Council uses AURORA to estimate the buildout of future resources throughout the western grid and generate wholesale power prices via production cost modeling. More on this market modeling methodology and the results can be found in Technical

Appendix L – Wholesale Market Availability Results. The resource options included in the capital expansion module in AURORA to be selected to meet forecasted WECC-wide load are the same as those described in this appendix. However, resources with locational variability, like wind and solar, required the development of additional generation curves to represent the diversity of the resource across the WECC. The selection of these representative locations, shown in Figure G - 8. Developing the accompanying generation profiles was done with a similar process as for in-region resources. These renewable availability forecasts were included in the AURORA capital expansion modeling as expected shapes based on historical climate data. Average monthly capacity factors by location are shown in Figure G - 9, to illustrate the spread of wind regimes represented across the larger WECC.

Figure G - 8: Out of Region Wind Locations

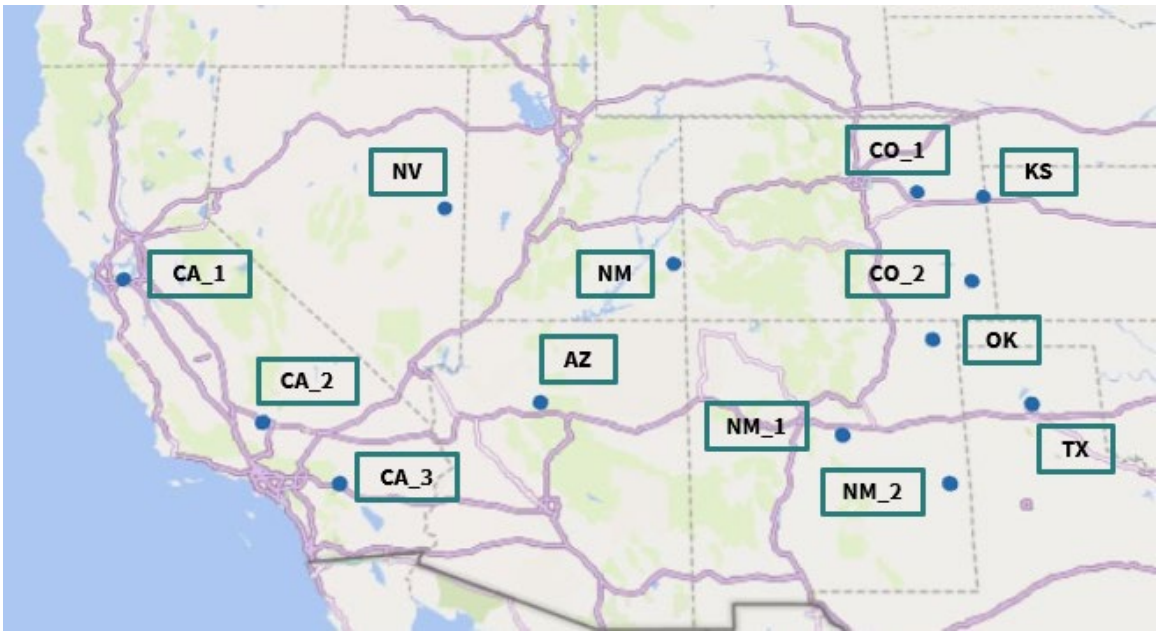
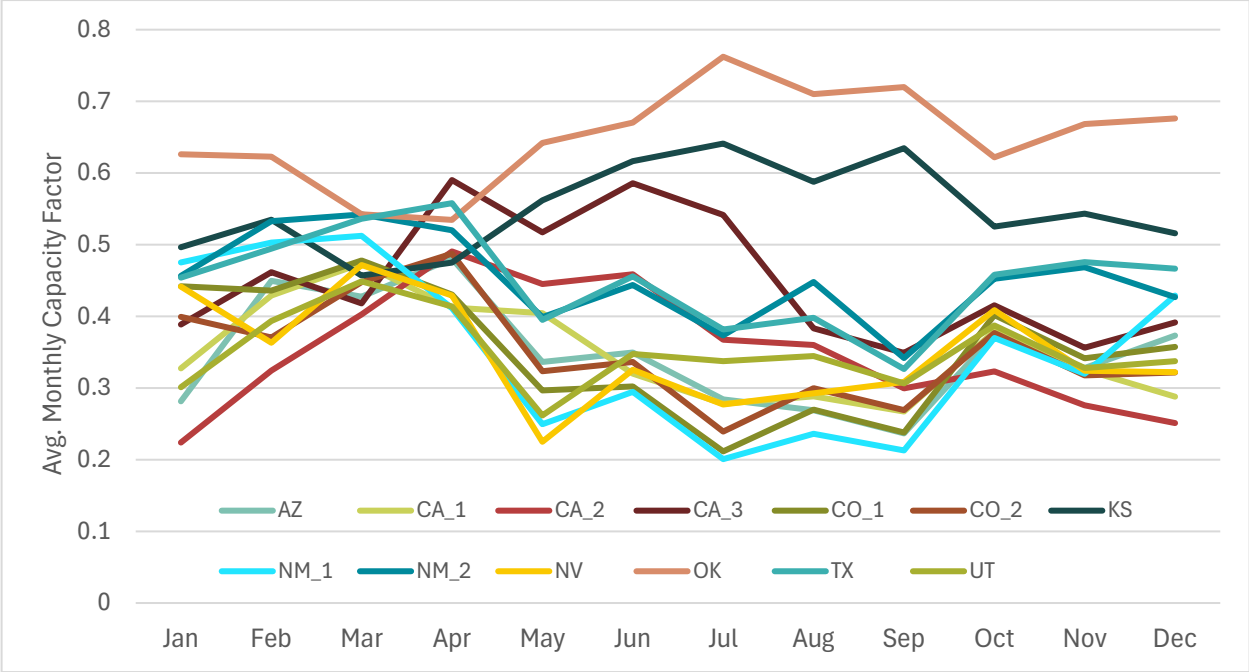


Figure G - 9 : Average WECC-Wide Monthly Wind Capacity Factors



Costs

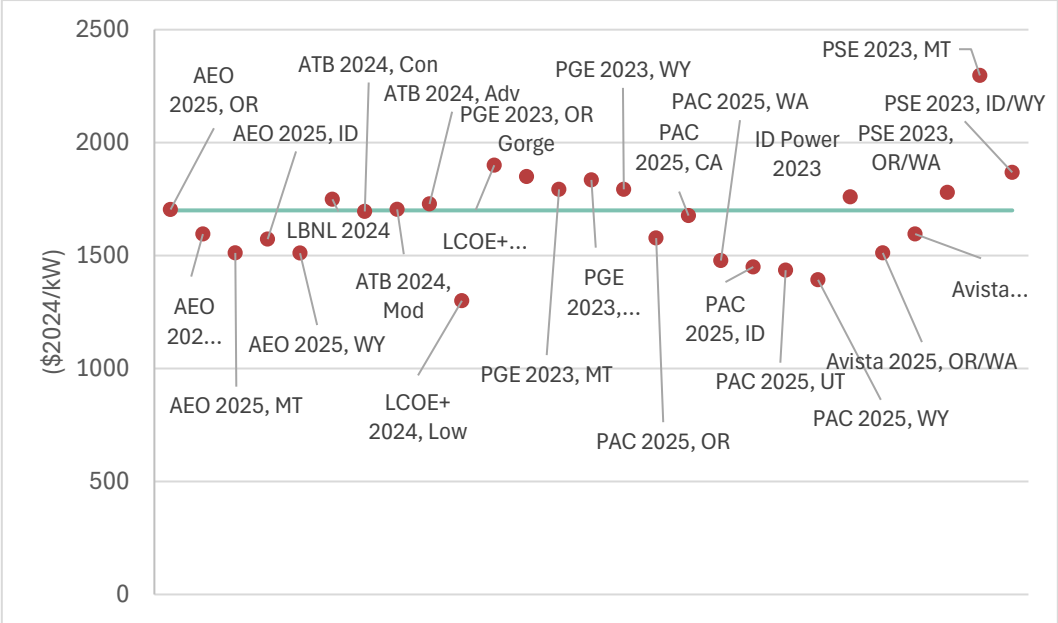
The capital costs of onshore wind technologies have declined significantly since they peaked in 2008-2009. According to the Lawrence Berkeley National Lab, from 2008 to 2020 the installed cost of wind declined by more than 50%, though recent years have seen that trend flatten as the technology has matured and faced some supply chain issues - particularly in 2021 and 2022.[40]

As wind turbine technologies have improved significantly over the last ten years, so too have the costs. Project performance and energy output has grown alongside increases in hub heights (size of the tower), rotor blades, and nameplate capacity of the generators. This has resulted in lower overall capital and installed costs (in $/kW), as well as the levelized cost of energy. Turbine generators are expected to continue to increase in capacity, and costs are expected to continue to decline, although to what extent is uncertain.

Figure G - 10 and Figure G - 11 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates. Note that figures capture data from various onshore wind capacities, configurations, and technologies.

[40] https://eta-publications.lbl.gov/sites/default/files/land-based_wind_market_report_2024_edition_executive_summary.pdf.

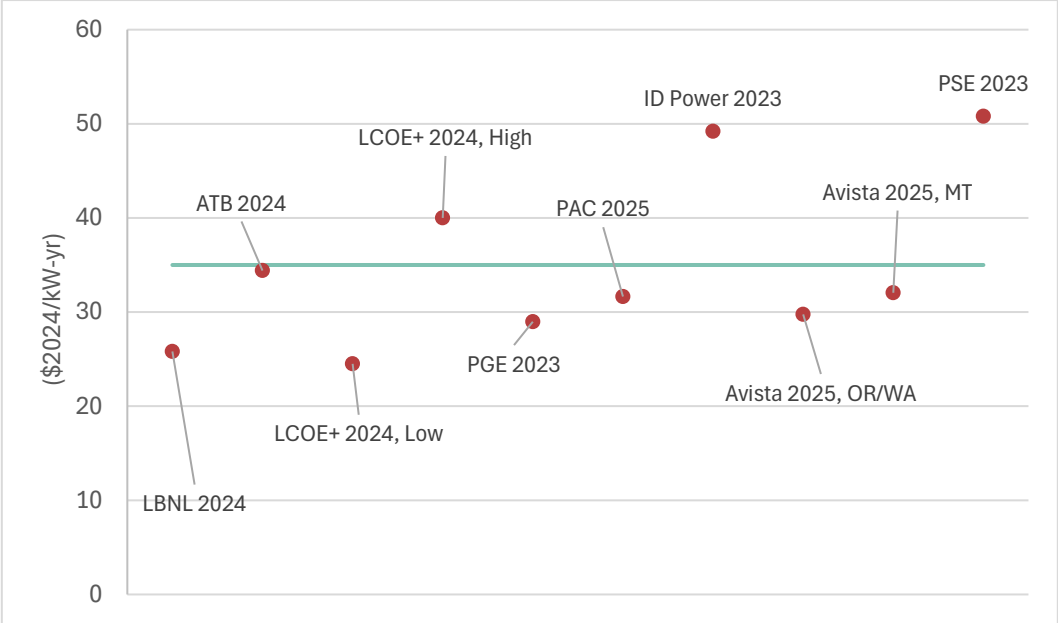
Figure G - 10: Literature Review of Land-Based Wind Overnight Capital Costs[41]



The literature review of onshore wind overnight capital costs, seen plotted in Figure G - 10, coalesces around $1700/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

[41] To avoid redundancy, all sources and their acronyms plotted on this and future charts are described in Table G - 6.

Figure G - 11: Literature Review of Land-Based Wind Fixed Operations & Maintenance Costs



Similarly, Figure G - 11 shows there is a clustering of wind fixed operations and maintenance costs around $30/kW-yr.

Figure G - 12: Forward Cost Curves for Land-Based Wind Overnight Capital Costs

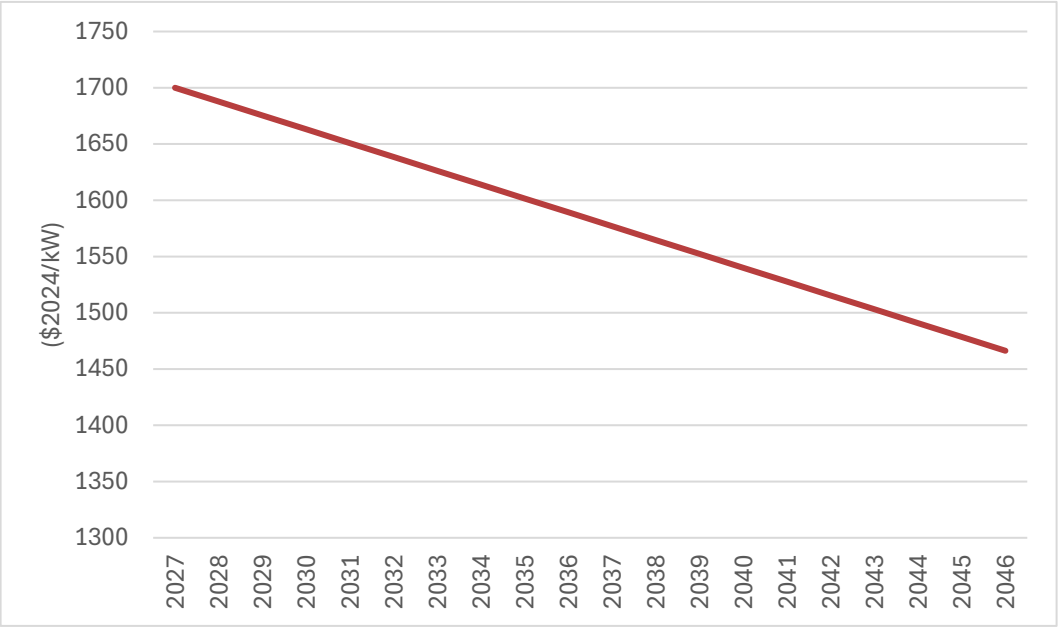


Figure G - 12 shows the same cost curve for wind displayed in Figure G - 1 but on its own axis for a clearer view. Overnight capital costs over the course of the study decrease to below $1500/kW over 20 years.

Locational Cost Variation

As discussed in the shared assumptions section about locational cost adjustments, locational cost adjustment factors are applied to the capital costs of resources that have otherwise been differentiated by location. For wind, the Council applied locational cost adjustments to align with the five different zones developed to capture capacity factor variation. There is some work aligning the factors provided by the EIA,[42] described in Table G - 3, to the locations selected for reference plants. That cross-walking for wind is shown in Table G - 9, where Gorge wind is given the Portland cost adjustment, SE Washington is given Spokane's etc. Those adjustments are applied by location to the starting wind capital cost in Table G - 10.

Table G - 9: Onshore Wind Locational Cost Variation by Resource Cluster

	Locations	Cost Variation Multiplier
Gorge	Portland	1.1080
SE Washington	Spokane	1.0376
S Idaho	Boise	1.0229
Montana	Great Falls	0.9830
Wyoming	Cheyenne	0.9825

Table G - 10: Locational Variation of Land-Based Wind Capital Costs

	Variation	Land-Based Wind, OCC
Starting Point	*n/a*	*$1700*
Gorge	1.108	$1883.60
SE Washington	1.3076	$1763.92
S Idaho	1.023	$1738.93
Montana	0.983	$1671.10
Wyoming	0.9825	$1670.25

Summary Table

In an effort to capture all the resource characteristics in one accessible and legible place, each reference plant description will conclude with a comparable table summarizing all that has been

[42] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

discussed in the preceding section. The summary of the onshore wind reference plant is captured by Table G - 11.

Table G - 11: Land-Based Wind Reference Plant Summary Table

Reference Plant	Onshore Wind – Gorge	Onshore Wind –SE. Washington	Onshore Wind – Southern Idaho	Onshore Wind – Montana	Onshore Wind – Wyoming
Configuration	Vestas V112-3.0, 100m hub height				
Location – Modeling Zones	BPA OR, BPA WA	BPA WA, AVA, DC/CC/GC PUD	IPCO, PACE ID	BPA IDMT, NWMT, WAUW	PACE WY, WACM
Year Available to Model	At start of study				
Development/Construction Period (Years)	3				
Capacity Factor	(See**Figure** G - 7)				
Overnight Capital Cost ($/kW)	1827	1768	1717	1666	1666
Fixed O&M Cost ($/kW-yr)	30				
Variable O&M ($/MWh)[43]	0				
Economic Life (years)	30				

Utility-Scale Solar

Solar power is a naturally occurring, renewable resource that converts energy from the sun (solar radiation) into electricity. Solar photovoltaic (PV) installations consist of PV cells assembled into modules, ground-mounted (as opposed to rooftop) on panels to fixed-tilt or tracking systems (single or dual axis). Because the electricity is generated in direct current (DC), it is fed through an inverter to convert the electricity output to alternating current (AC). From the inverter, it is connected to the electricity grid through a transformer and substation. PV modules are typically manufactured from semiconductor materials, primarily crystalline silicon (c-Si) and cadmium tellurium (CdTe). Fixed-tilt are stationary installations, permanently set at an optimum angle to absorb the most solar radiation. Tracking systems allow for the modules to rotate on a single or dual axis, effectively "tracking" the

[43] The operations and maintenance of renewable resources, like wind, are primarily fixed annual costs that occur independently of the plant's production. Variable O&M costs are a function of a plants usage, incurring per megawatt hour, and as renewable fuels, sun and wind, are free they don't result in any consumable costs, unlike fossil fuel plants.

greatest solar radiance throughout the day. While the range in spatial acreage can vary based on each project design and logistics, a basic rule of thumb is that one megawatt capacity of solar PV tends to equal about five to seven acres of land.

In the Pacific Northwest there is a tendency to install single-axis tracking systems, rather than fixed-tilt mounted systems. The Northwest has lower solar radiance (as compared to the desert Southwest, for example), so using a technology that can track and capture more energy from the sun increases energy output.

For more information about solar development in the region see Technical Appendix B – Existing System Parameters and Policies.

Availability

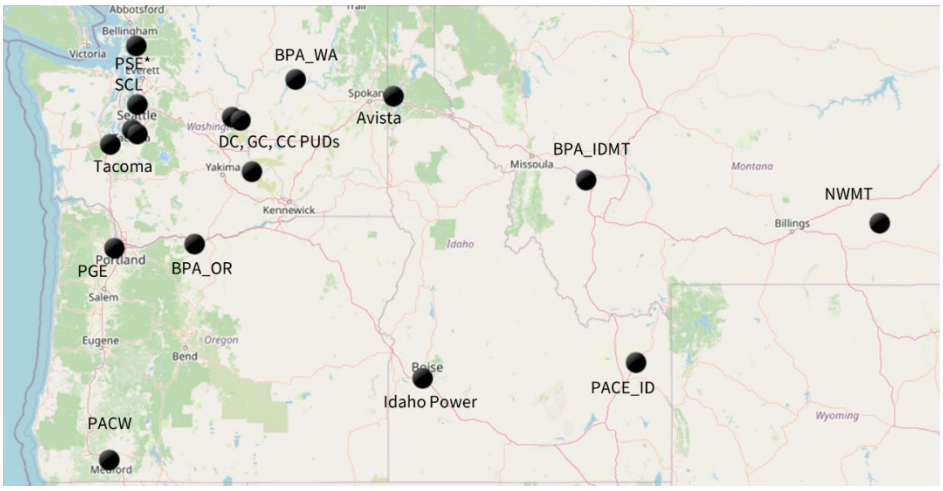
Utility-scale solar is available to be selected at the beginning of the study period and takes two years for development and construction. Solar is another continuous resource and therefore does not have a defined plant capacity.

Location

Similarly to wind, there is significant variation in solar generation across the region. This variability led to a similar exercise of trying to capture that variation without needing to define a solar reference plant for each modeling zone. An exploration of solar generation across the region, shown in Figure G - 14, saw zones cluster into three groups with comparable generation shapes. The locations of those zones are mapped in Figure G - 13.

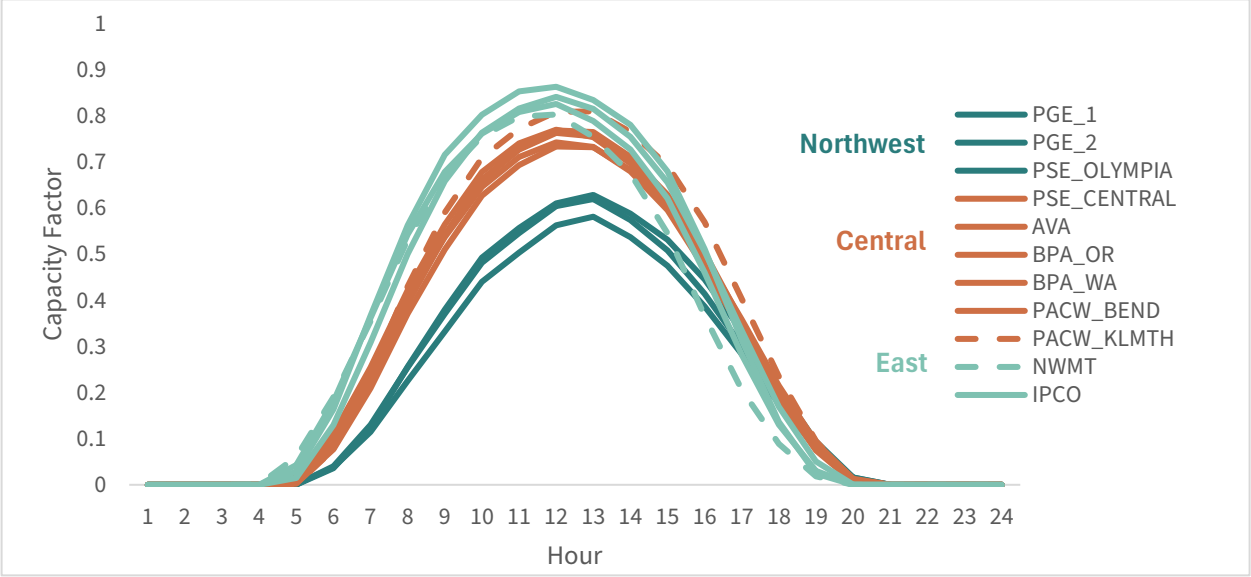
As might be anticipated, there is a higher generation shape for eastern zones like PACE and Idaho Power, a moderated shape for the central region including BPA OR and WA, PACW, and lower generation in the furthest west zones such as PSE and PGE. Figure G - 15 displays how these three broader clusters encompass existing resource locations as well.

Figure G - 13: Modeling Zones Mapped[44]



As might be anticipated, there is a higher generation shape for eastern zones like PACE and Idaho Power, a moderated shape for the central region including BPA OR and WA, PACW, and lower generation in the furthest west zones such as PSE and PGE. Figure G - 15 displays how these three broader clusters encompass existing resource locations as well.

Figure G - 14: Clustering of Solar Shapes

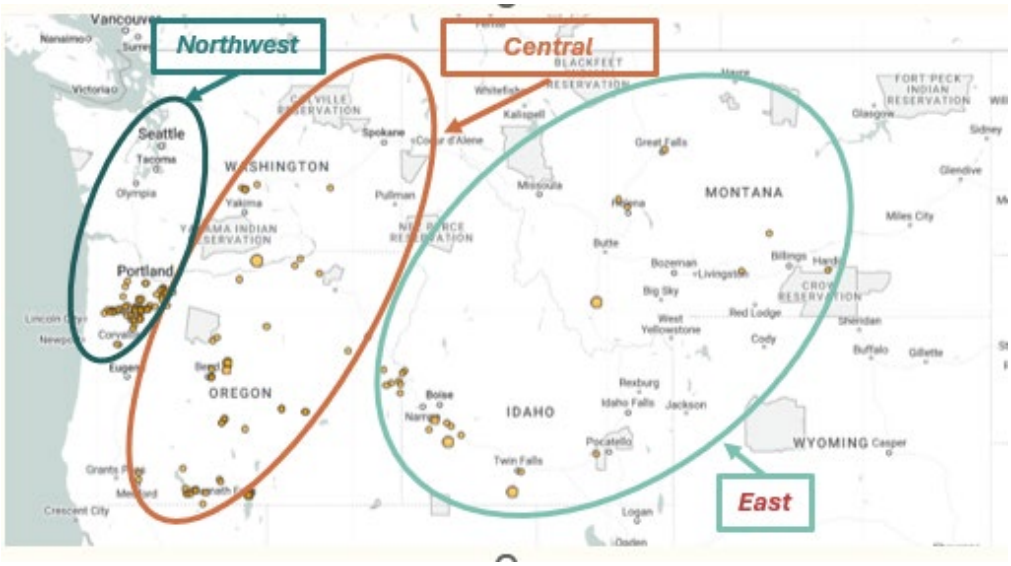


The exploration of in-region solar capacity factor shapes in Figure G - 14 suggests three potential clusters which are observed daily (shown in this chart) & monthly. These capacity factors are synthetic, based on historical solar generation from Time Series Lab. The exact numbers shown above

[44] Mapped black dots identify GENESYS zones which are not identical to those in OptGen, but are close enough to illustrate the methodology being described here.

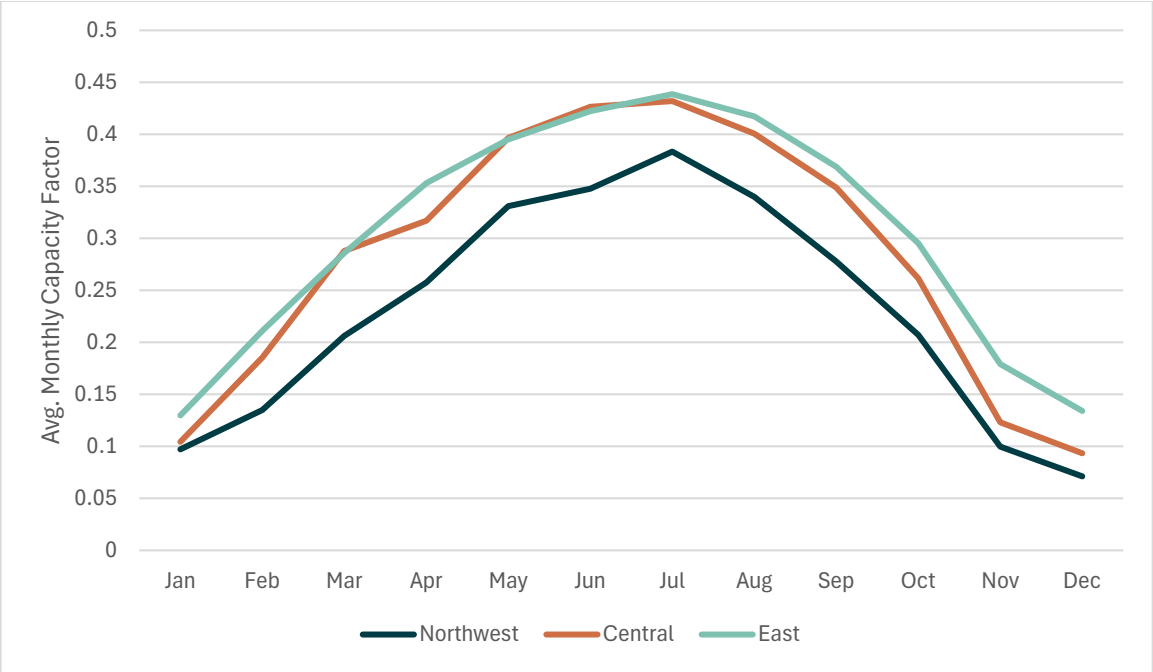
are pre-climate change processing and bias correction, and are therefore just illustrative of hourly generation by BA, not the actual solar capacity factors used in modeling. Final capacity factors are illustrated in Figure G - 16.

Figure G - 15: Regional Solar Generation Shape Clustering



After selecting the representative locations, synthetic future generation curves were developed for each, like those shown in Figure G - 16, but for every hour of every day for each location for the whole study. More on this development process is detailed in Technical Appendix D – Climate Change Data and Assumptions.

Figure G - 16: Average Monthly Capacity Factors Across Regional Solar Generation Clusters

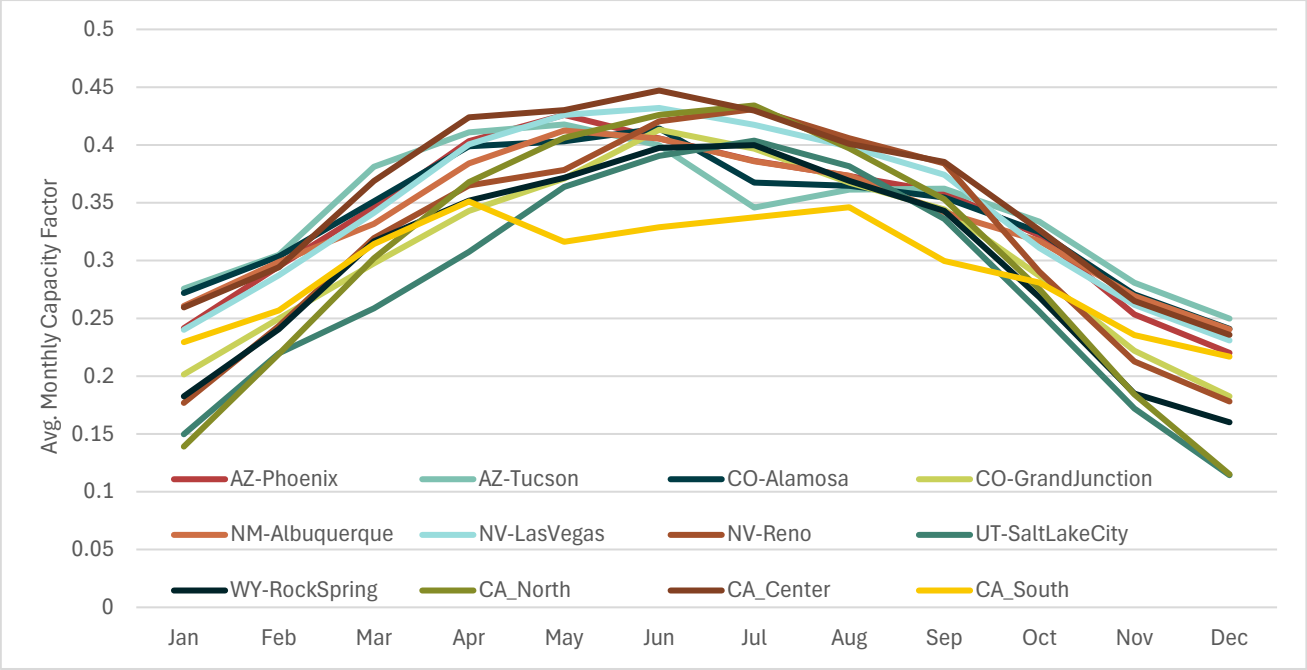


Out of Region Solar Locations

As with the wind resource, to accurately represent solar in the market availability study, the Council had to develop additional renewable availability forecasts to capture the locational diversity of the resource. The specific locations selected to represent the broader WECC's solar resource are shown mapped in Figure G - 17 below. Those locations' generation curves are broadly illustrated in Figure G - 18 as average monthly capacity factors.

Figure G - 17: Out of Region Solar Locations

Figure G - 18: Average WECC-Wide Monthly Solar Capacity Factors



Operational Risk of Wildfire

In recent years, greater attention has been given to the operational risk of wildfires on the bulk power system. The Council initially considered the adequacy risk of wildfires in the region from the perspective of transmission derating in the 2027 Adequacy Assessment[45] in one of the evaluated scenarios. The scenario was considered as a stress test, and derated three transmission lines between BPA, PacifiCorp West, and Idaho Power by 50-90% for an entire week in July. While that specific scenario was deemed adequate (all adequacy metrics were satisfied), it does not mean that there is no adequacy risk to the region from wildfires. Rather, it was a deterministic representation of a single wildfire event. In preparation for the Ninth Plan, the Council sought to transition from a standalone "wildfire scenario" to "wildfire-informed" planning included in all scenarios.

To that end, the scope of wildfire operational risks in the Ninth Plan centers on wildfires' impacts on bulk transmission and generation and its influence on new resource decisions and adequacy. This was done via literature review, subject matter expert interviews, and advisory committee engagement in an effort to enhance the modeling and fine tune risk assumptions.[46,47]

[45] Pacific Northwest Power Supply Adequacy Assessment for 2027, Council Document Number 2023-1, Jan 17, 2023 https://www.nwcouncil.org/fs/18158/2023-1_adequacyassessment.pdf.
[46] https://www.nwcouncil.org/calendar/approach-to-modeling-operational-risks-from-wildfires-webinar-2025-03-07/
[47] https://www.nwcouncil.org/fs/19395/2025_05_11.pdf.

Through this process, the two main bulk system operational risks that were determined to be appropriate to model were transmission derates and smoke-modified solar capacity factors. However, it was judged that the methodology required to represent transmission derates consistent with the effect on solar generation in the model setup would not be possible to implement within the Ninth Plan timeline. Further methodological and model development will be pursued to capture the effect in future plans. Instead, the wildfire risk in this plan is focused only on smoke-modified solar capacity factors.

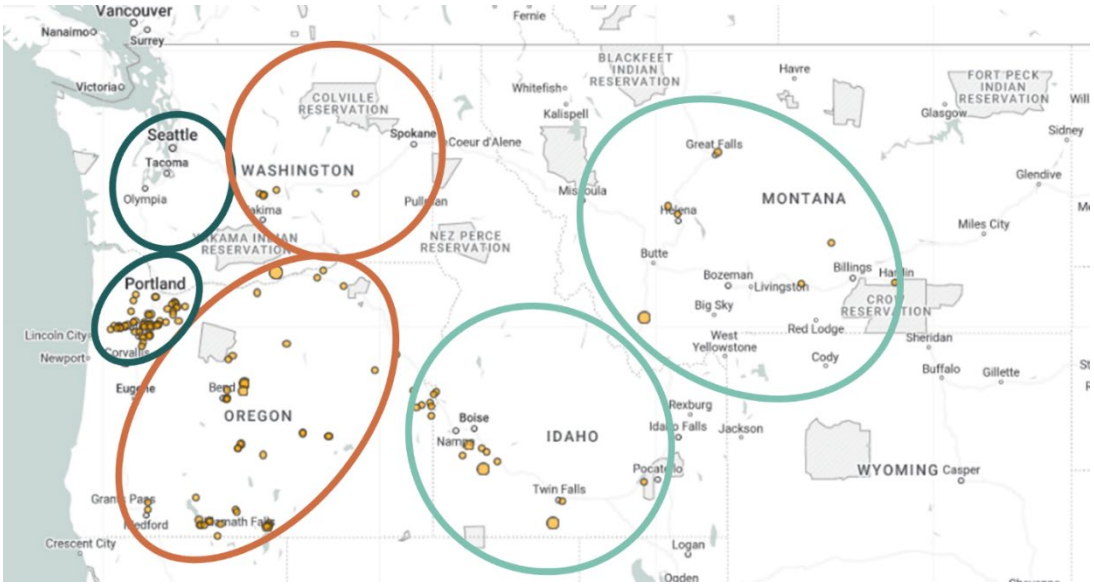
Smoke-Modified Solar Capacity Factor:

Research indicates that the impact of smoke on reducing solar generation can range from average daily reductions of 5-40%.[48,49,50,51,52] Coupled with the reduced capacity, there is also an increase in balancing up reserves, with one NLR report examining California fires finding a ~10% solar reduction but 53-64% reserve increase.[53] Given these potential impacts, it was deemed important to include smoke risks in the hourly annual solar capacity factors used in Council models.[54]

The first step was to define the smoke areas in the region. As solar shapes were already grouped into the three zones seen in Figure G - 15, it was recommended to further divide the three zones into their own state areas and evaluate smoke in those perimeters, for a total of six smoke zones seen in Figure G - 19.

[48] Ali, Amjad Jebril, Long Zhao, and Mohammad Heidari Kapourchali. "Data-driven-based analysis and modeling for the impact of wildfire smoke on PV systems." *IEEE Transactions on Industry Applications* 60.2 (2023): 2076-2084.
[49] Gilletly, Samuel D., Nicole D. Jackson, and Andrea Staid. "Evaluating the impact of wildfire smoke on solar photovoltaic production." *Applied Energy* 348 (2023): 121303.
[50] York, S. "Smoke from California wildfires decreases solar generation in CAISO." *US Energy Information Administration* (2020).
[51] Maguire, Gavin. "California Wildfires Dim Solar Generation during Power Demand Peak | Reuters." *Reuters*, 31 July 2024, www.reuters.com/markets/commodities/california-wildfires-dim-solar-generation-during-power-demand-peak-2024-07-31.
[52] Cai, Mengmeng, et al. *Final technical report: impact of wildfires on solar generation, reserves, and energy prices*. No. NREL/TP-5D00-86640. National Renewable Energy Laboratory (NREL), Golden, CO (United States), 2023.
[53] Ibid
[54] See Technical Appendix K – Modeling Framework for more information on the Council's modeling methodology.

Figure G - 19: Regional Solar Generation Shape Clustering for Wildfire Modification



Second, the Council approximated the days with smoke present using historical observations from 2015-2024 using collected particulate matter 2.5 (PM2.5)[55] data from several monitoring stations in each zone. While PM2.5 has limitations as a proxy for wildfire smoke, the Council assumed that locations that had levels higher than normal background levels (for example from emitting industries) could suggest the prevalence of wildfire smoke.[56]

Figure G - 20 and Figure G - 21 show the location of the PM2.5 monitoring sensors with daily measurements provided from the U.S. Forest Service AirFire Research Team,[57] which include sensor level data across each state for the last 10 years (2015-2024). These locations were selected based on the presence of existing solar projects, seen in Figure G - 21, possible locations of future projects, and available data for 2015-2024 with as little missing data as possible.

[55] PM2.5 are fine inhalable particles, with diameters that are generally 2.5 micrometers and smaller. They are dangerous to human health due to their small size and resulting ability to permeate the respiratory system.
[56] Gilletly, Samuel D., Nicole D. Jackson, and Andrea Staid. "Evaluating the impact of wildfire smoke on solar photovoltaic production." *Applied Energy* 348 (2023): 121303.
[57] https://www.airfire.org.

Figure G - 20: AirFire PM2.5 Sensor Locations by Group[58]

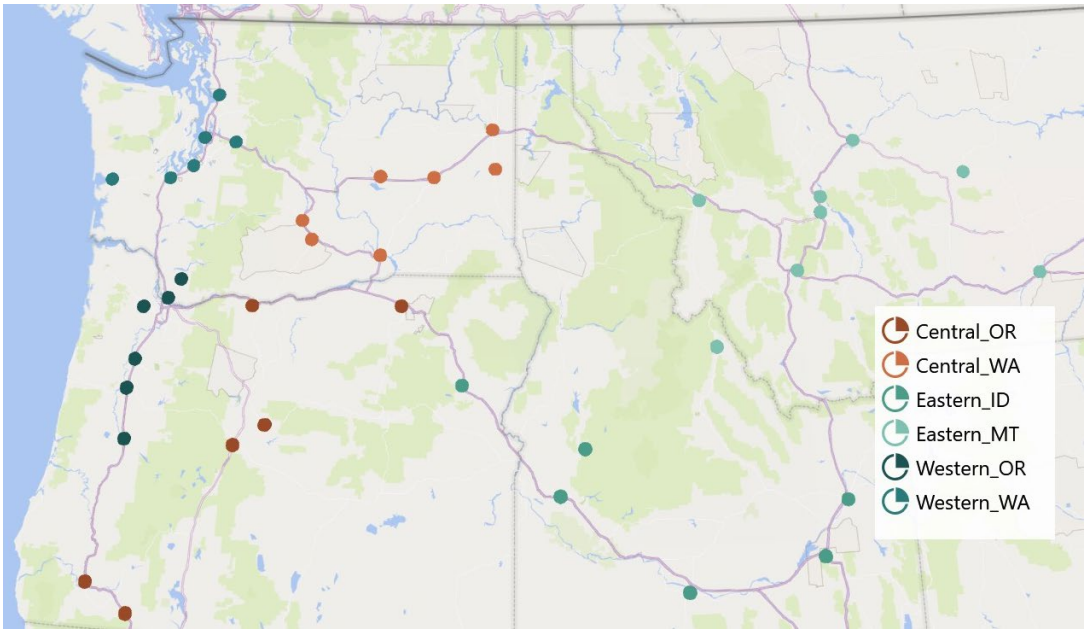
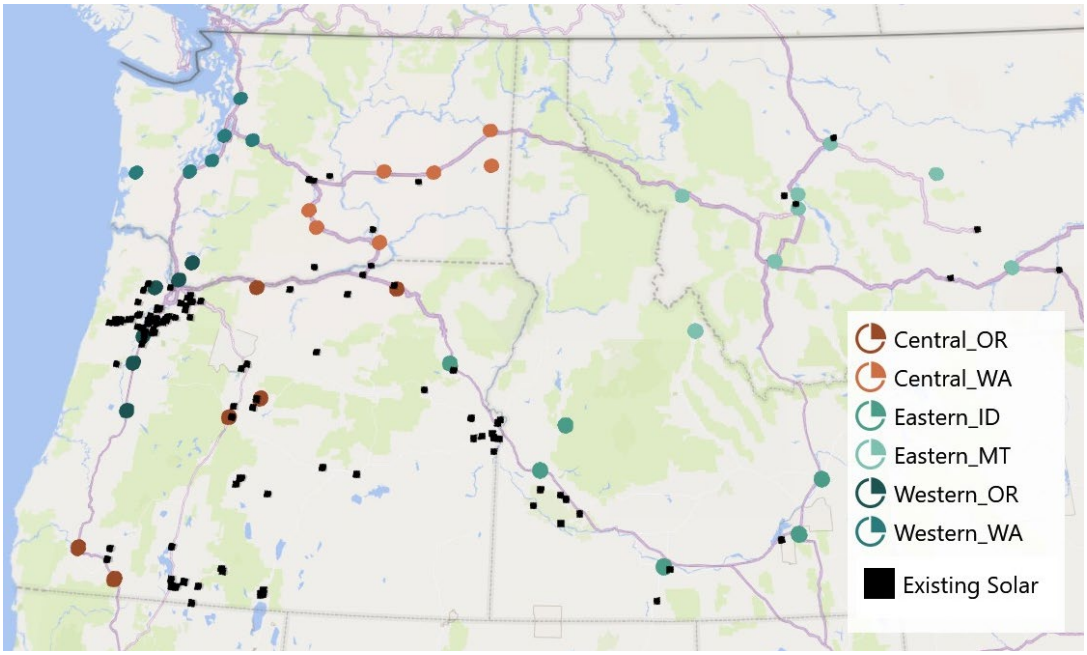


Figure G - 21: AirFire PM2.5 Sensor Locations Near Spread of Existing Solar Projects in Region[59]



[58] https://www.airfire.org.
[59] Ibid.

As each subregion has 6-7 sensors and their aggregate was determined to be the daily average of the zone. The Council needed to define a "wildfire smoke day" and did so assuming any day at or above 35 µg/m3 was a result of wildfires. Because the Council's models do not have the ability to represent nuances within a zone (e.g. different capacity factors for two solar plants within the same zone), the Council needed an approach that captured the impacts of smoke while not over representing localized impacts that would ultimately not be considered in the modeling.

After determining the location and frequency of wildfires, the next step was to define the solar reduction factor, or how much the presence of smoke impacts the production of solar. Given the findings from several studies centered around 10% reduction, staff determined a range of 8-12% reduction to be uniformly randomly assigned to any day with an average PM2.5 value at or above 35 µg/m3. Lastly, these daily smoke and solar reduction factors were then used to create annual profiles, based on the available 2015-2024 data, which are then used to modify the existing solar capacity factors. The analysis highlights the smoke patterns in the region with Figure G - 22 showing the average PM2.5 values at different times that correspond to major fires.

Figure G - 23: Average Daily PM2.5 per Smoke Zone for Council Models (2022-2024)

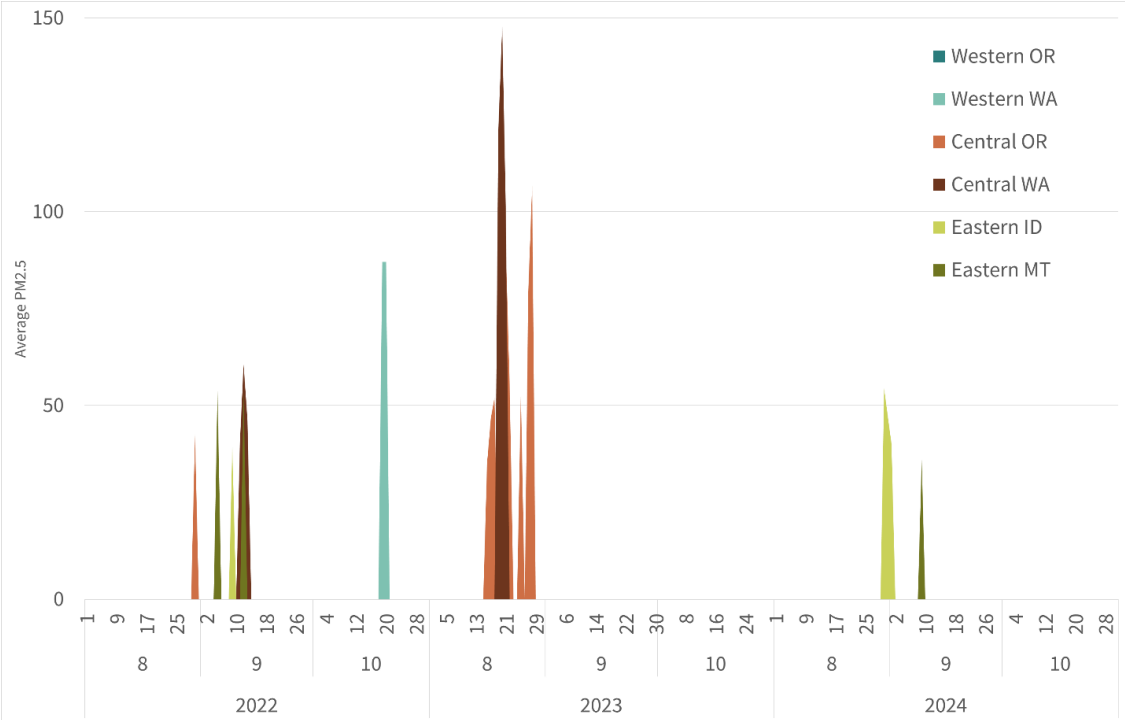
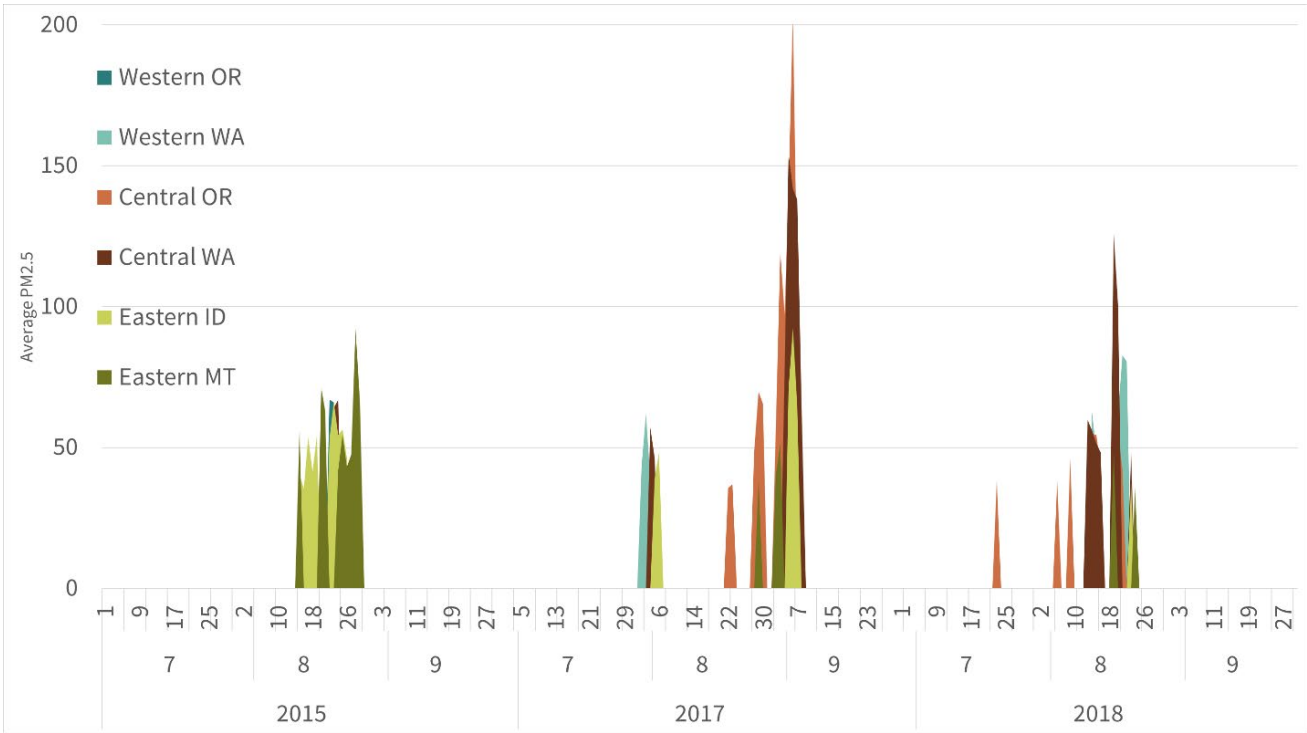


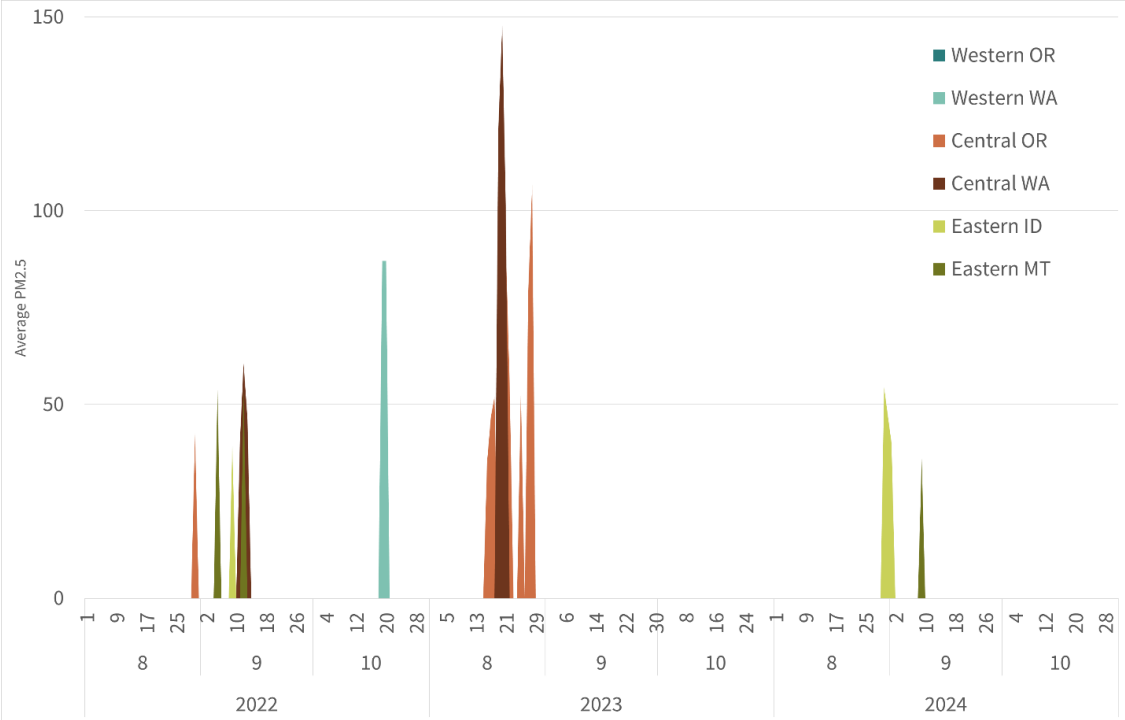
Figure G - 24 translates these into number of smoke days per year in each smoke zone.

Figure G - 22: Average Daily PM2.5 per Smoke Zone for Council Models (2015-2019)[60]



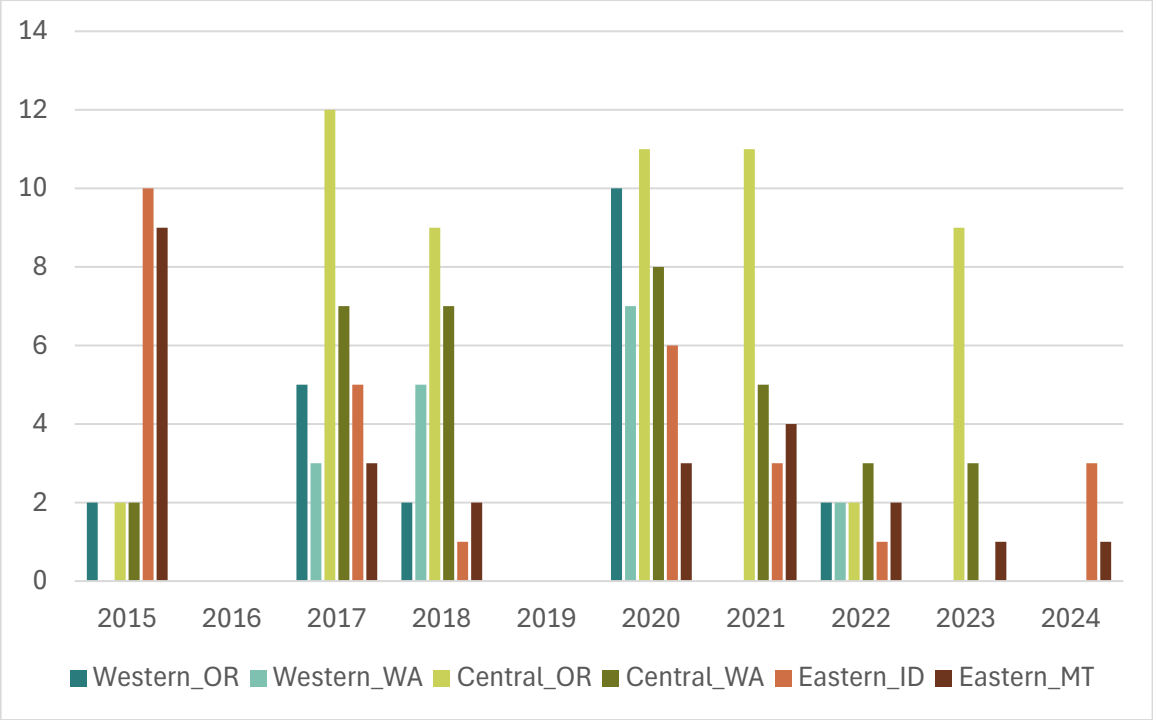
[60] Years and months without any days with an air quality above 35 µg/m3 have been excluded from this figure for the sake of legibility

Figure G - 23: Average Daily PM2.5 per Smoke Zone for Council Models (2022-2024)[61]



[61] Years 2020 and 2021 were high smoke years and are pulled out into their own charts as further illustration of the data. See Figure G - 21 and Figure G - 22.

Figure G - 24: Modeled Number of Smoke Days per Year



The years 2020 and 2021 offer examples of how the whole region was impacted by smoke, seen in Figure G - 25 and Figure G - 26. These graphs show the days across the summer months of 2020 and 2021 with the highest PM2.5 levels. Figure G - 25 shows a large event in September of 2020 that impacted the whole region across zones. Figure G - 26 shows a broader time span where more discrete wildfire events occurred in different zones across the season.

Figure G - 25: Example of Wildfire Days from the Summer of 2020 Across Zones

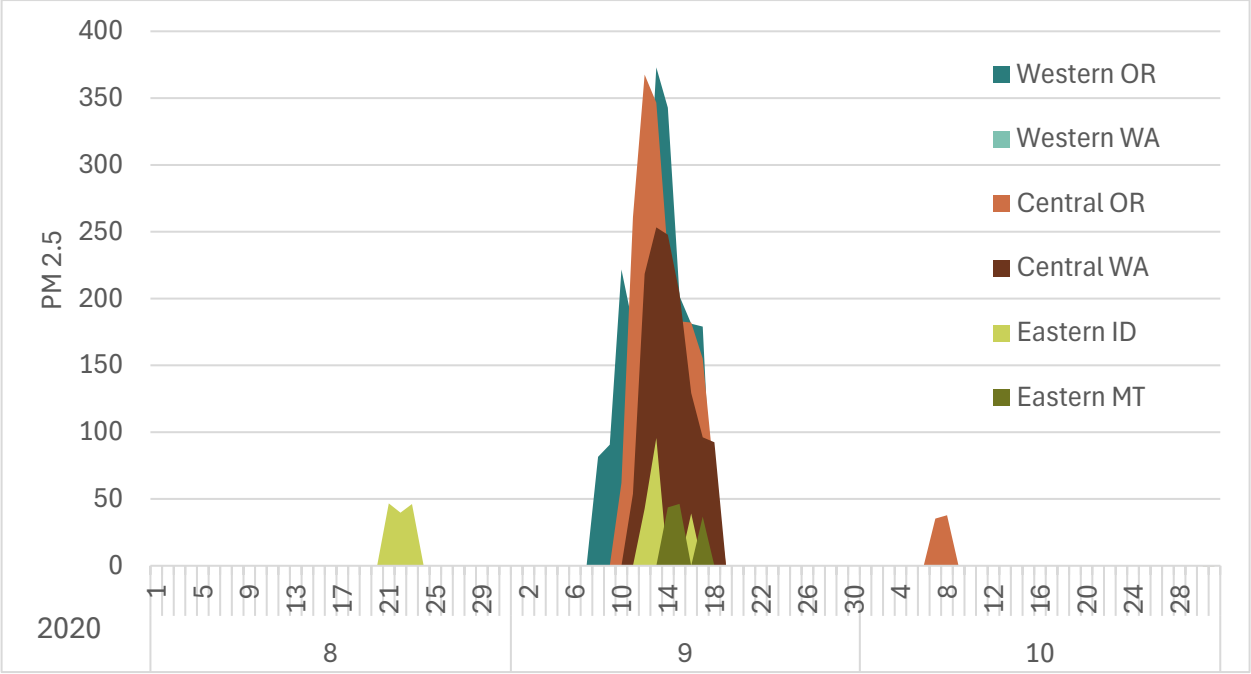
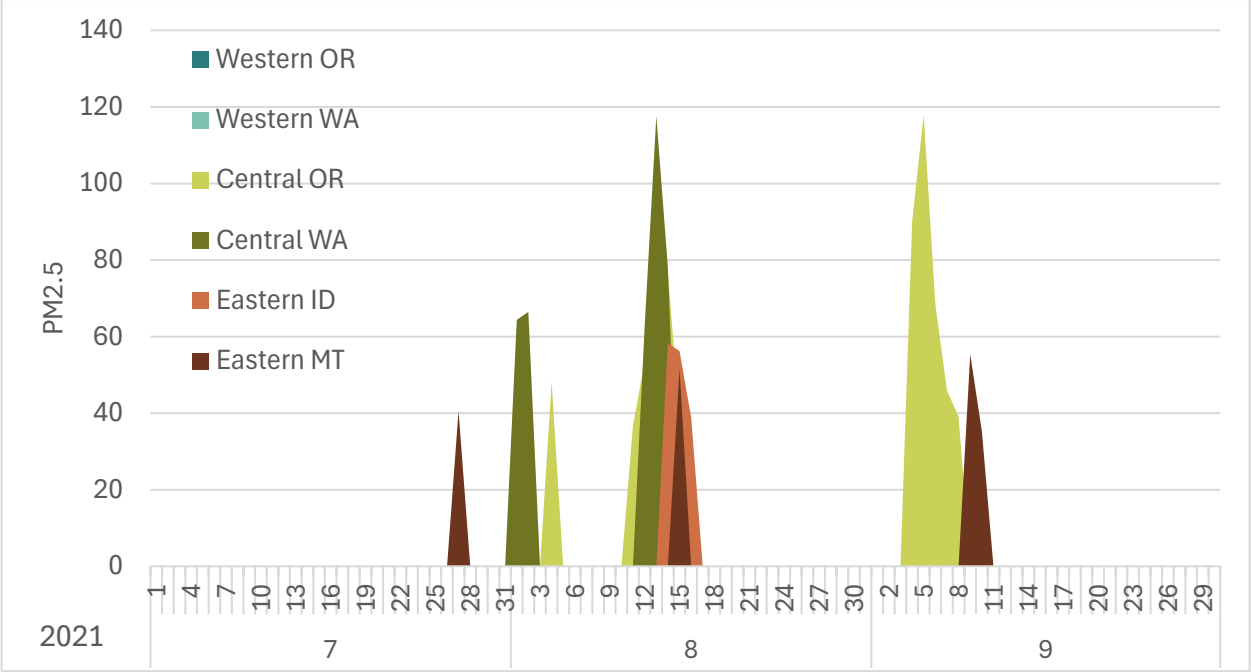
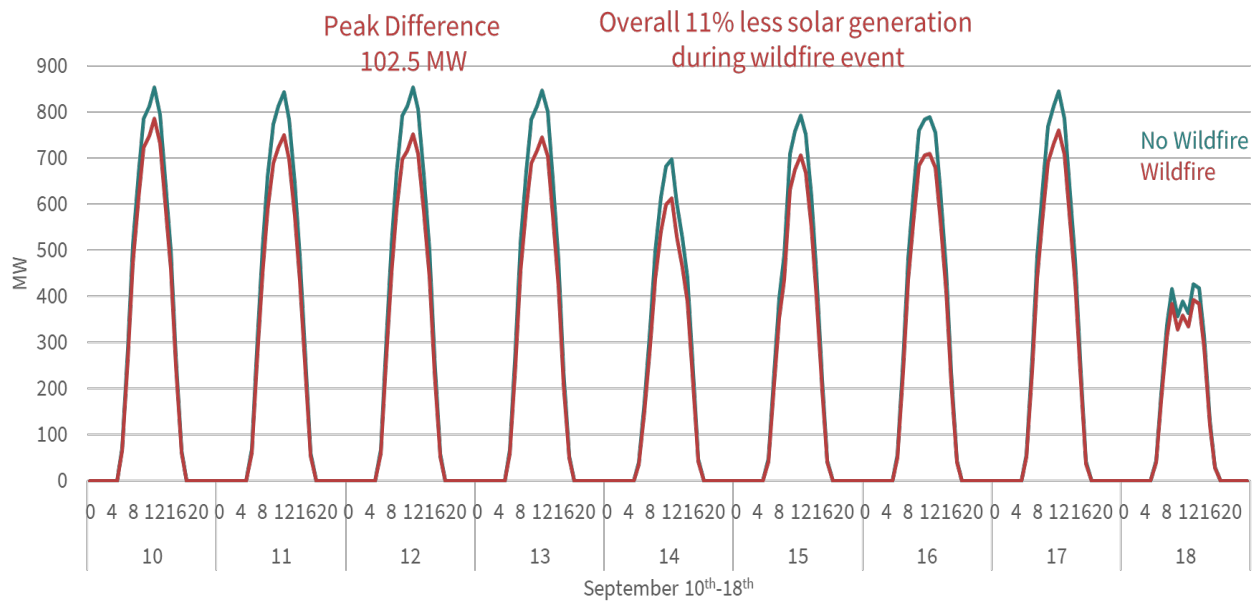


Figure G - 26: Example of Wildfire Days from the Summer of 2021 Across Zones



An example of how the data is used is seen in Figure G - 27 for a theoretical 1,000 MW solar project in central Oregon and how it would perform under a "2020 September wildfire" event. The teal line shows the solar generation under no wildfire conditions, and the red shows the reduction in the same week after the smoke reduction modification. In this example, there's a peak reduction of 102.5 MW, and 11% less generation in general throughout the week.

Figure G - 27: Theoretical Example of Applied Smoke Reduction Modification

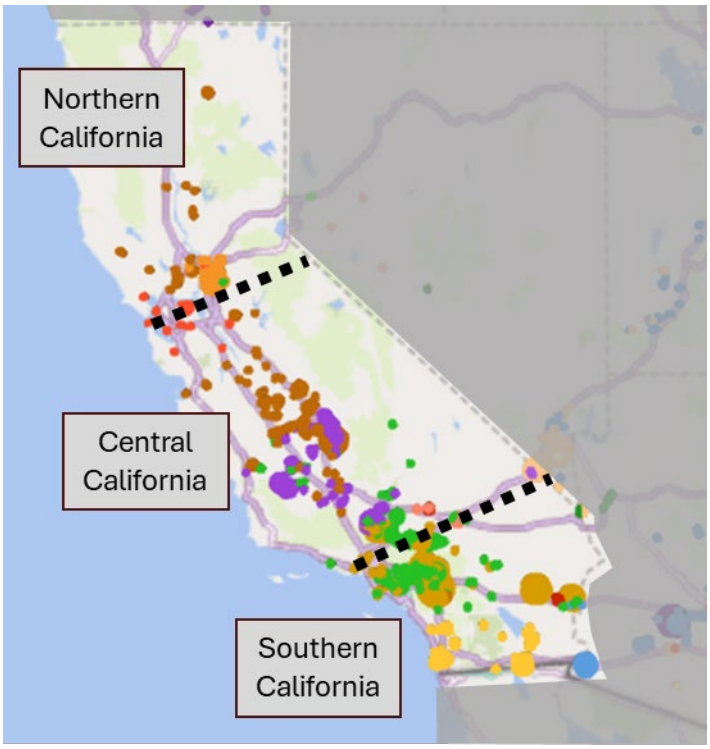


In practice, it is possible that actual fires will have greater or smaller impacts, but from a modeling representation, this approach further enhances risk representation within current modeling capabilities. The modified solar generation shapes are used to inform adequacy in GENESYS and resource decisions in OptGen to deliver a finer locational value due to the risk of wildfire smoke, and future work will aim to enhance the alignment with transmission derates as well.

California

Because California has significant amounts of solar and a history of major wildfires, this influences regional market dynamics. The Council determined it important to also capture the risk of smoke impacts in California. Figure G - 28 shows the location and clusters of most California solar projects and how the state was divided into northern, central and southern smoke zones. A similar approach to the one described above for the region was taken in California to come up with smoke days and solar reduction profiles.

Figure G - 28: California Solar and Smoke Zones



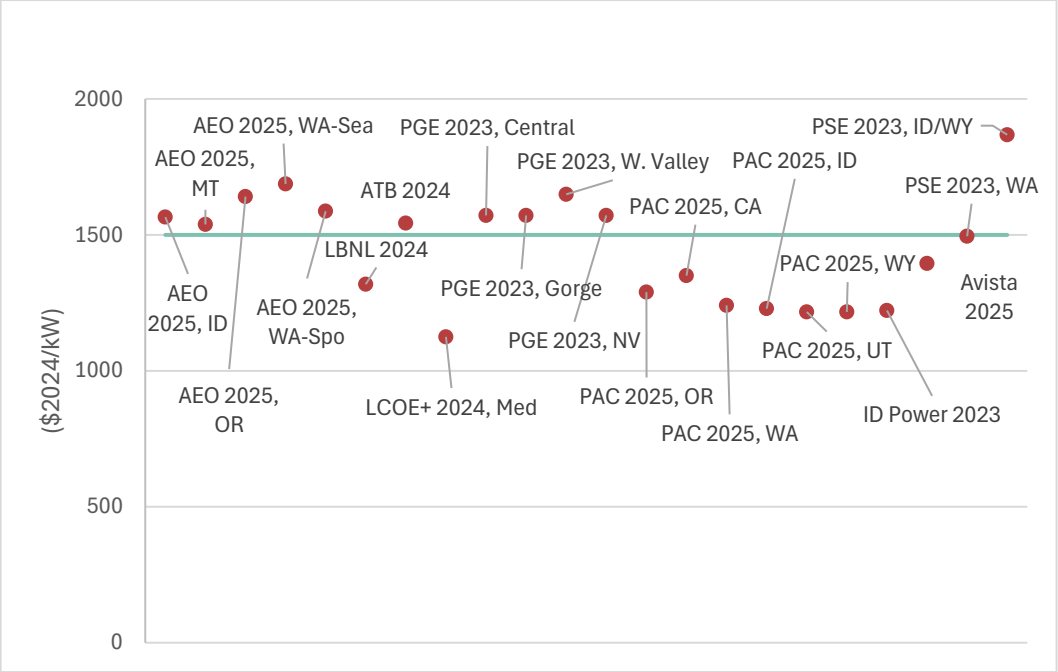
Costs

The installed cost of utility-scale solar PV has declined significantly since the first major installations in the late 2000s and early 2010s. Over the past decade, the median installed cost of utility-scale solar projects has declined 75% since 2010 according to LBNL.[62] This decline in solar costs has been driven by efficiencies and improvements across all components, in particular the module (panel), hardware, and soft costs.

Figure G - 29 and Figure G - 30 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates. Note that these figures capture data from various solar PV capacities, configurations, and technologies.

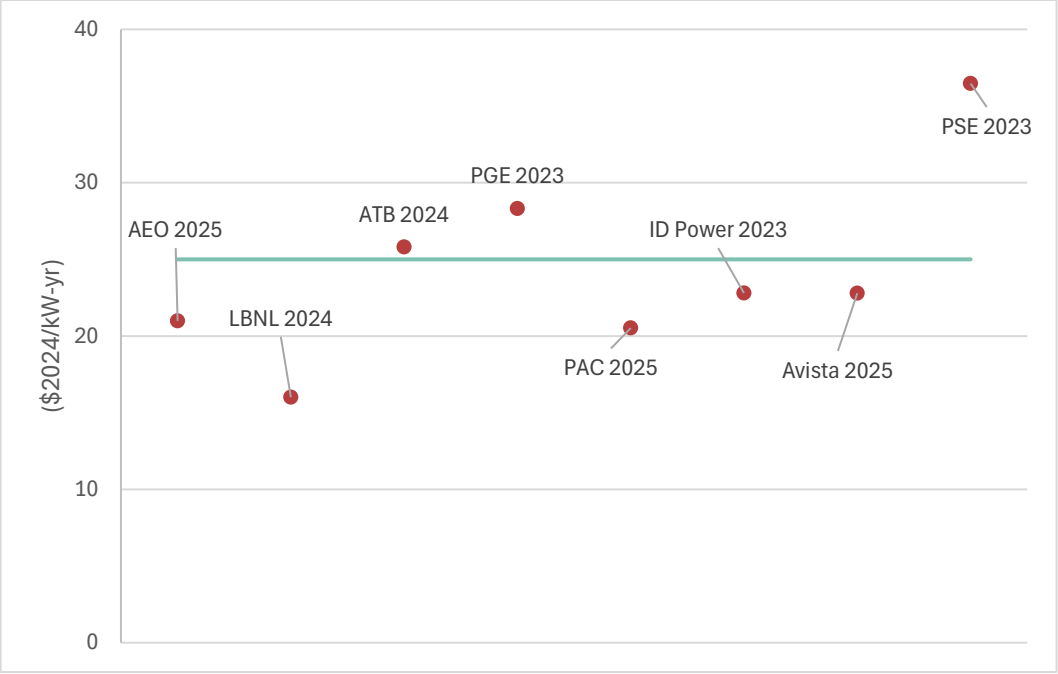
[62] https://emp.lbl.gov/publications/utility-scale-solar-2024-edition.

Figure G - 29: Literature Review of Utility Scale Solar Overnight Capital Costs



The literature review of utility-scale overnight capital costs, seen plotted Figure G - 29, groups around $1500/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 30: Literature Review of Utility Scale Solar Operations & Maintenance Costs



Similarly, Figure G - 30 shows there is a clustering of utility-scale solar fixed operations and maintenance costs around $25/kW-yr.

Figure G - 31: Forward Cost Curves for Utility-Scale Solar Overnight Capital Costs

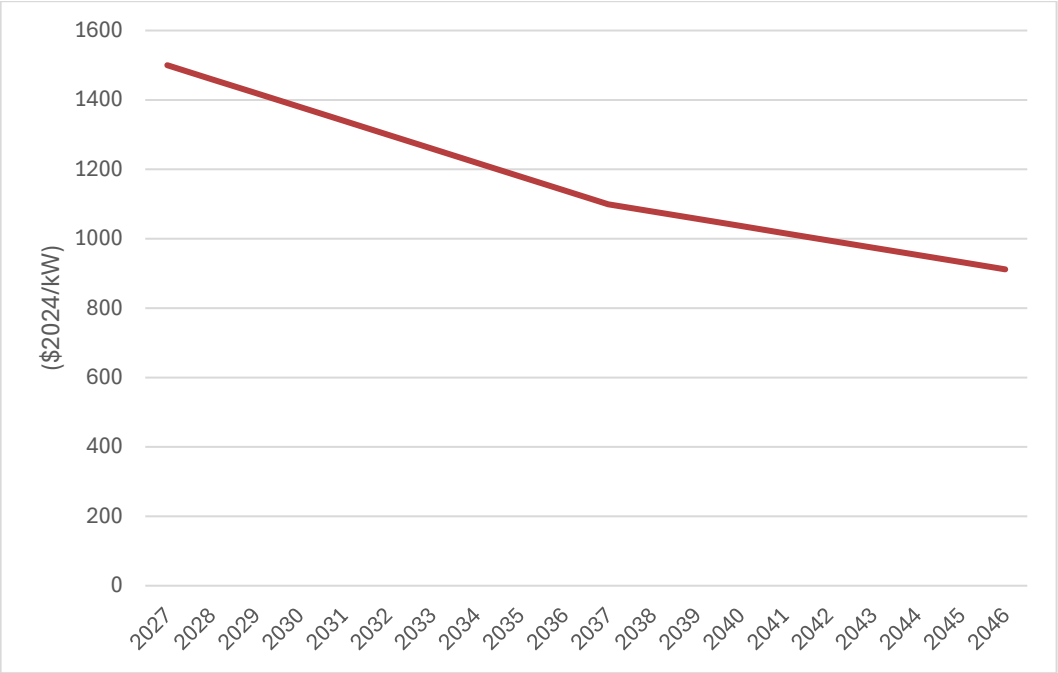


Figure G - 31 shows the same cost curve for utility-scale solar displayed in Figure G - 1, but on its own axis for a clearer view. Overnight capital costs over the course of the study deescalate to under $900/kW over 20 years, with a steeper decline in the first 10 years.

Locational Cost Variation

As discussed in the shared assumptions section about locational cost adjustments, locational cost adjustment factors are applied to the capital costs of resources that have otherwise been differentiated by location. Because solar has multiple reference plants to account for differences in capacity factors, the Council also applies locational cost adjustment factors. The location groupings are chosen agnostic to the adjustment factors and so there is some work behind aligning the factors provided by the EIA, described in Table G - 3, to the locations selected for the solar reference plants. That cross-walking is shown in

Table G - 12, where northwest solar zone is given the average of Portland and Seattle's cost adjustments, central solar is given Spokane's etc. Those adjustments are applied by location to the starting solar capital cost in Table G - 13.

Table G - 12: Solar Locational Cost Variation by Resource Cluster

	Locations	Cost Variation Multiplier	
		Utility Scale & Small Scale	***+ Battery***
Northwest	Porland, Seattle	1.073	1.075
Central	Spokane	1.023	1.025
East	Great Falls, Boise	1.001	1.001

Table G - 13: Locational Variation of Utility Scale Solar Capital Costs

	Variation	Utility-Scale Solar, OCC
Starting Point	*n/a*	*$1500*
Northwest	1.073	$1609.50
Central	1.023	$1534.95
East	1.0005	$1500.75

Summary Table

The summary of the utility-scale solar reference plant is captured by Table G - 14.

Table G - 14: Utility-Scale Solar Reference Plant Summary Table

Reference Plant	Solar PV – Northwest	Solar PV – Central	Solar PV – East
Configuration	Mono PERC c-SI with single axis tracker		
Location – Modeling zones	PGE	BPA OR/WA, AVA, PACW, DC/CC/GC PUD	BPA IDMT, PACE, IPCO, NWMT
Year Available to Model	At start of study		
Development/Construction Period (Years)	2		
Inverter Loading Ratio (DC:AC Ratio)	1.4:1		
Capacity Factor	See shape (Figure G - 16)		
Overnight Capital Cost ($/kW)	1612	1575	1500
Fixed O&M Cost ($/kW-yr)	25		
Variable O&M ($/MWh)[63]	0		
Economic Life (years)	30		

Small-Scale Solar

Small-scale solar in the Ninth Plan refers to primarily community solar applications that are local solar facilities shared by multiple community subscribers who receive credit on their electricity bills for their share of power produced. The 'small-scale' title casts a broader net and avoids confusion around legal definitions of community solar that vary by jurisdiction. However, most small-scale solar facilities being built in the region are some form of community solar and are usually less than five megawatts of electrical capacity. Unlike residential or commercial solar development, these solar resources are generally built on leased land. Because of this, these resources can provide homeowners, renters, and businesses equal access to the economic and environmental benefits of solar energy regardless of the physical attributes or ownership of their home.

Oregon and Washington have both passed community solar enabling legislation, which has driven their development in recent years. Washington passed the Washington Community Solar Program (2SHB 1814) in 2022 which set the project size and payment rate for eligible plants with the intention of expanding equitable access of renewable energy benefits through community solar projects. The Oregon Community Solar Program was passed in 2017 (SB 1547) and directed the Oregon Public

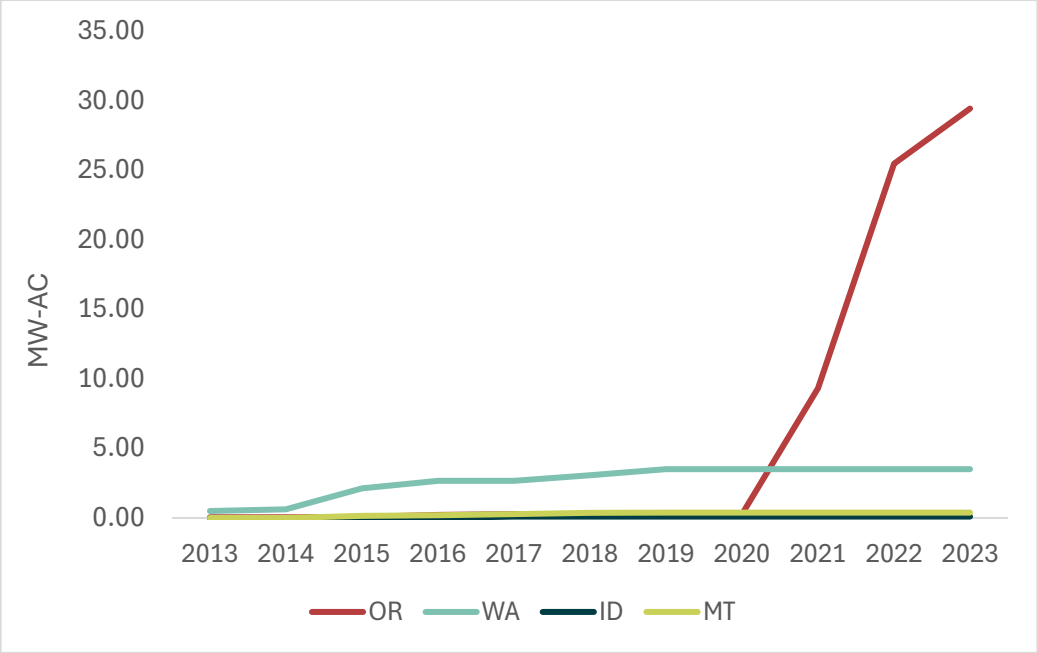
[63] Solar does not incur any variable costs for the same reason as wind, renewable O&M costs are fixed, not reliant on the production of the plant.

Utility Commission to define the size, participation etc. of a community solar project, which it did via OAR 860-88 in 2022. Oregon's renewable portfolio standard also requires at least 8% of Oregon's aggregate electrical capacity come from small-scale, community renewable energy projects, though not explicitly defined as community solar, with a capacity of 20 MW or less. This concerted legislative effort can be seen in the recent uptick in small-scale solar development particularly in those states, illustrated Table G - 15 and Figure G - 32 below.

Table G - 15: Small-Scale Solar Regional Project Details

States	# of Projects	Total Installed Capacity (MW-AC)	Average Size of Project (MW-AC)
Idaho	2	0.1	0.05
Montana	8	0.38	0.05
Oregon	23	29.44	1.28
Washington	35	3.51	0.10
Grand Total	**68**	**33.44**	**0.49**

Figure G - 32: Capacity Installed Small-Scale Solar[64]



Availability

Small-scale solar is available at the beginning of the study and takes only half a year for development and construction.

Small-scale solar is more expensive on a per-kW basis relative to utility-scale solar. However, it does offer the small size advantage and is therefore able to be built faster and in more locations. The generation shapes of small-scale solar mirror those of utility-scale, but due to its size the resource is available in all modeling zones.

Also, similar to utility-scale solar, small-scale solar can be selected on a continuous basis by the model. In reality, by virtue of being small in scale, this resource's capacity would be limited to 3 MW-20 MW per individual plant. However, in a given zone the model does not see individual plants, just total resource built in that particular zone, so specifying an exact capacity is not necessary.

Costs

Community or small-scale solar share many of the same costs as utility-scale solar, but is more expensive than utility-scale primarily due to "soft costs" or initial costs incurred from acquiring numerous subscribers. Community solar systems also incur unique costs for ongoing subscriber management, such as bill management, ongoing marketing, and customer acquisition costs to

[64] Data from Figure G - 28 and Table G - 15 are from NLR's Sharing the Sun Community Solar Project Database (https://data.nrel.gov/submissions/233).

manage customer turnover. Those cost components are shown in Figure G - 33. The data behind this figure is from NLR's Solar-PV cost benchmarks analysis.[65] The Council did not use these exact costs, but instead leveraged the data on the relationship between the different components of the cost in defining the final reference plant costs.

Figure G - 33: Component Cost of Community Solar Installations

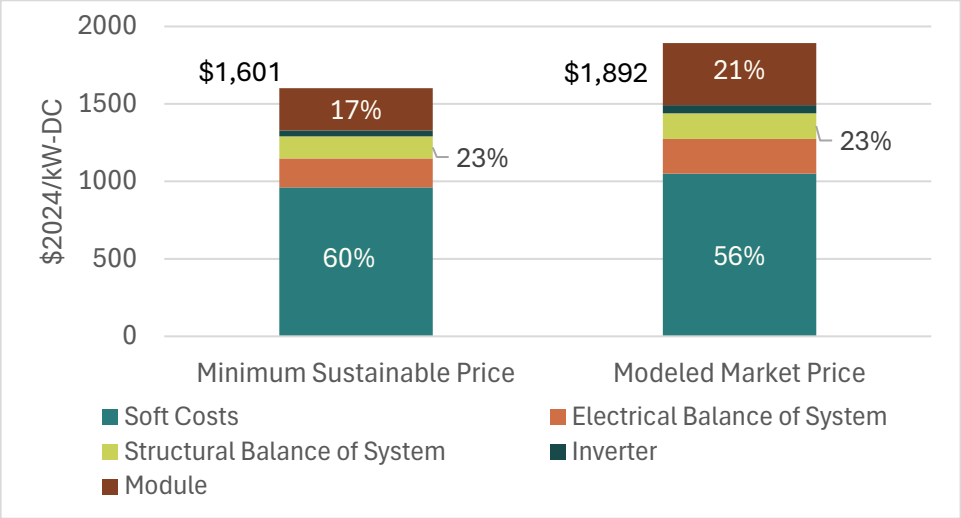


Table G - 16 summarizes the small-scale solar costs used in the Ninth Plan. The cost values were developed through literature review and then adjusted based on professional judgment of regional experts. The final cost was, in part, based on the utility scale solar costs with adjustments made for the soft costs described above.

Table G - 16: Literature Review of Small-Scale Solar Costs

Source	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capacity (MW)
PAC IRP (2025)	1960	19	20 MWac
NLR	1660-1960	13 (+22.47 for program management)	3 MWdc[66]
PGE IRP (2023)	2400		50MWac

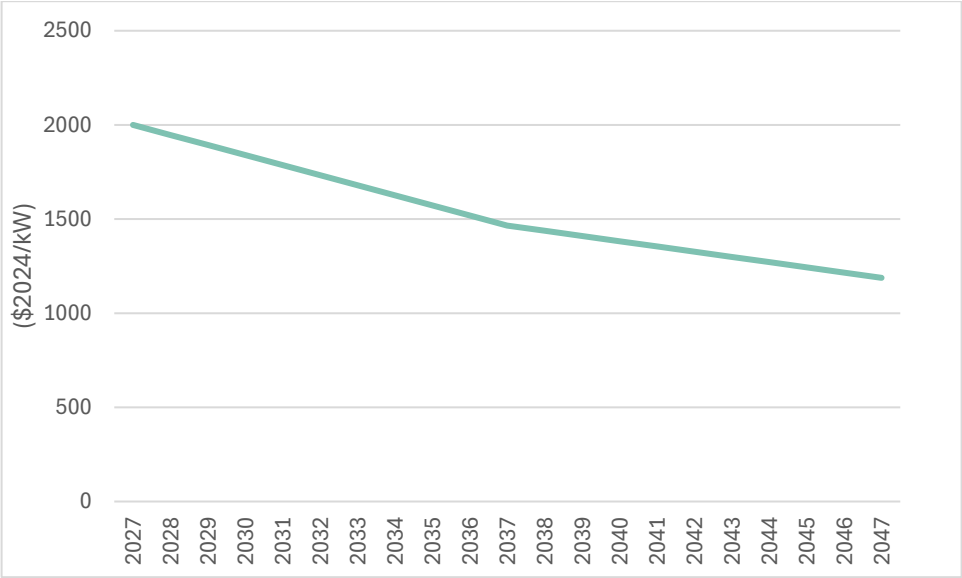
Figure G - 34 shows the same cost curve for small-scale solar displayed in Figure G - 1 but on its own axis for a clearer view. Small-scale solar's cost curve mirrors utility-scale solar as they are the same

[65] Data from NLR U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023: https://docs.nrel.gov/docs/fy23osti/87303.pdf.

[66] This NLR report notes that the per-unit cost results are meant to be generally applicable to systems with PV sizes between about 1.5 and 6 MWdc.

technology, applied differently. Overnight capital costs over the course of the study deescalate to around $1100/kW over 20 years.

Figure G - 34: Forward Cost Curves for Small-Scale Solar Overnight Capital Costs



Locational Cost Variation

Small-scale solar mirrors the locational differentiation of utility-scale solar, as they are capturing the same renewable resource. More detail on that process is included in the utility-scale solar section and will not be replicated here. Those adjustments by zone are applied by location to the starting solar capital cost in Table G - 17.

Table G - 17: Locational Variation of Small-Scale Solar Capital Costs

	Variation	Small-Scale Solar, OCC
Starting Point	*n/a*	*$2000*
Northwest	1.073	$2146.00
Central	1.023	$2046.60
East	1.0005	$2001.00

Summary Table

The summary of the small-scale solar reference plant is captured by Table G - 18.

Table G - 18: Small-Scale Solar Reference Plant Summary Table

Reference Plant	Small-Scale Solar
Configuration	Ground mounted single axis

Reference Plant	Small-Scale Solar
Location	All zones
Year Available to Model	Start of study
Development Period (Years)	1
Construction Period (Years)	6 mo.
Capacity Factor	See shape(Figure G - 16)
Overnight Capital Cost ($/kW)	2000
Fixed O&M Cost ($/kW-yr)	35
Variable O&M ($/MWh)[67]	0
Economic Life (years)	30

Lithium-Ion Battery

Utility-scale, standalone (not paired directly with a generating resource) battery storage allows for the capture and storage of energy for future use. Conventional batteries are composed of cells which contain two electrodes, a cathode and an anode, and electrolyte in a sealed container. During discharge a reduction-oxidation reaction occurs in the cell and electrons migrate from the anode to the cathode. During recharge, the reaction is reversed through the ionization of the electrolyte. Many different combinations of electrodes and electrolytes have been developed. Battery storage systems are not geographically dependent and can be utilized at multiple locations and for a variety of applications.

Lithium-ion (Li-Ion) battery technology has long been used in consumer electronics and electric vehicles and is now emerging as the dominant choice for battery storage systems. Utility-scale Li-Ion batteries are typically a collection of tens of thousands of small batteries (approximately AA size) connected and packaged together to form a larger resource. The fundamental composition of each cell is several stacks of brittle thin film anode/cathode pairs separated by an electrolyte. During discharge, lithium ions migrate from the anode into the porous crystalline solid cathode to form a chemical bond which releases energy through a metal current collector to provide power to the grid. This reference plant is for a 4-hour lithium-ion battery, meaning it discharges its full rated power for four consecutive hours. 4-hour durations have been and are anticipated to continue to be the most typical in the utility-scale market.[68]

[67] Resources without fuel do not have variable O&M costs.
[68] https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

For more information about battery development in the region see Technical Appendix B – Existing System Parameters and Policies.

Availability

Lithium-Ion batteries are available beginning of study and require two years for development and construction. Unlike more weather dependent, renewable resources, batteries operate the same across the region and so only one reference plant was developed.

Batteries are another resource selected continuously, because their capacity is easily scaled within a single plant so a set size is not necessary.

Round trip efficiency (RTE) refers to the ratio of useful energy output to useful energy input. It is an important factor to consider in understanding how efficiently this technology can store and discharge energy, and how much electricity is loss in the process. A literature review of assumed RTE for lithium-ion batteries, shown in Table G - 19 below, sees fairly cohesive percentages ranging from 85%-90%. With the expertise of the Generating Resource Advisory Committee, 88% RTE was selected for this reference resource.

Table G - 19: Battery Storage Efficiency Literature Review

Source	Round-Trip Efficiency
NLR's Annual Technology Baseline 2024	85%
NLR Technical Report on Cost Projections for Utility-Scale Battery[69] Storage	85%
PNNL's ESGC and Performance Database 2024	83-85%
Lazard's Levelized Cost of Storage	90%
PGE 2023 IRP	86%
PacifiCorp 2025 draft IRP	85%
Avista 2025 IRP	87%
Puget Sound Energy 2023 IRP Progress Report	85%

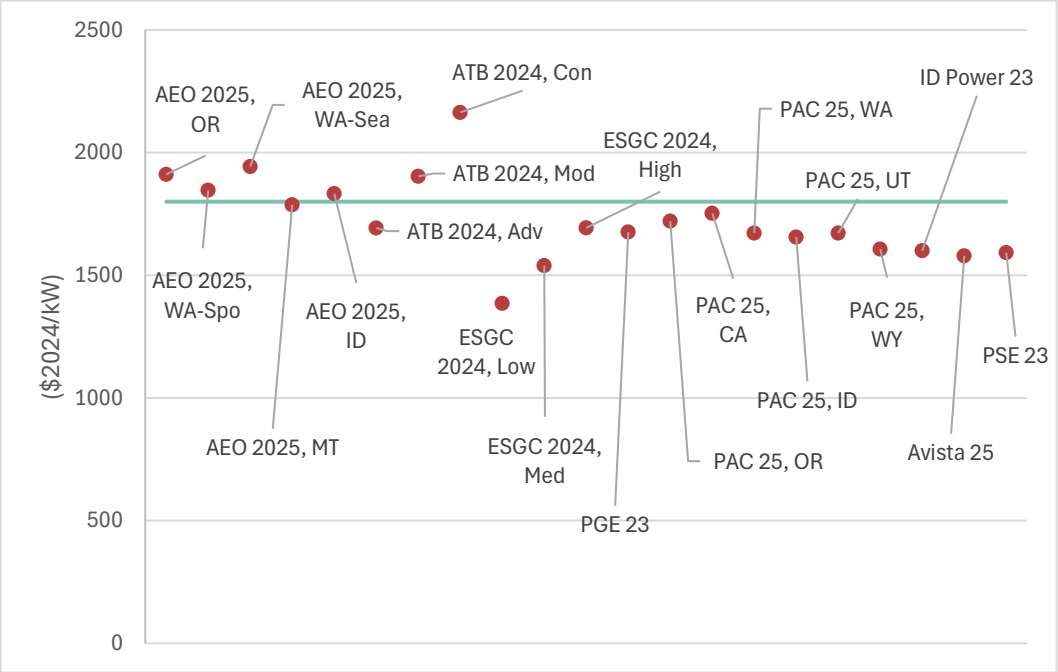
[69] https://docs.nlr.gov/docs/fy23osti/85332.pdf.

Costs

As batteries have become a more essential piece of electricity grids in the U.S., costs have dropped significantly. This follows similar trends of recent decades for resources like natural gas, wind, and then solar. Lithium-ion batteries costs have fallen more than 70% over the past 10 years.[70]

Figure G - 35 and Figure G - 36 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates.

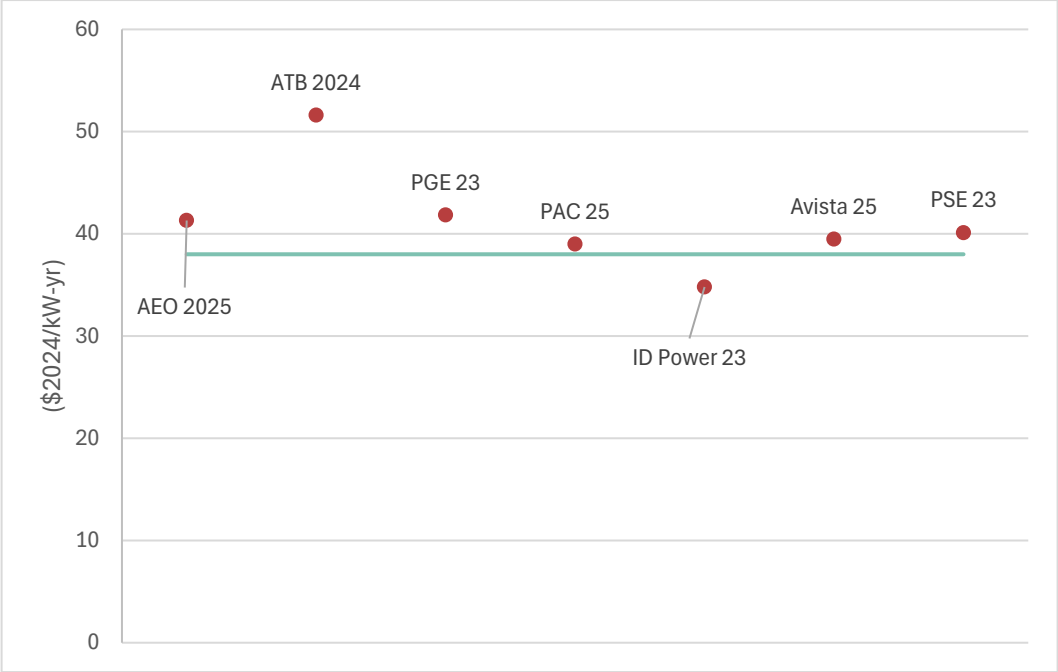
Figure G - 35: Literature Review of Li-Ion Battery Overnight Capital Costs



The literature review of Li-ion Battery overnight capital costs, seen plotted Figure G - 35, aggregates around $1800/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

[70] https://about.bnef.com/insights/clean-transport/lithium-ion-battery-pack-prices-fall-to-108-per-kilowatt-hour-despite-rising-metal-prices-bloombergnef/#:~:text=BNEF's%20industry%2Dleading%20battery%20price,renewables%20integration%20around%20the%20world.%20%E2%80%9D.

Figure G - 36: Literature Review of Li-Ion Battery Fixed Operations & Maintenance Costs



Similarly, Figure G - 36 shows there is a clustering of Li-ion battery fixed operations and maintenance costs around $38/kW-yr.

Figure G - 37: Forward Cost Curves for Li-Ion Battery Overnight Capital Costs

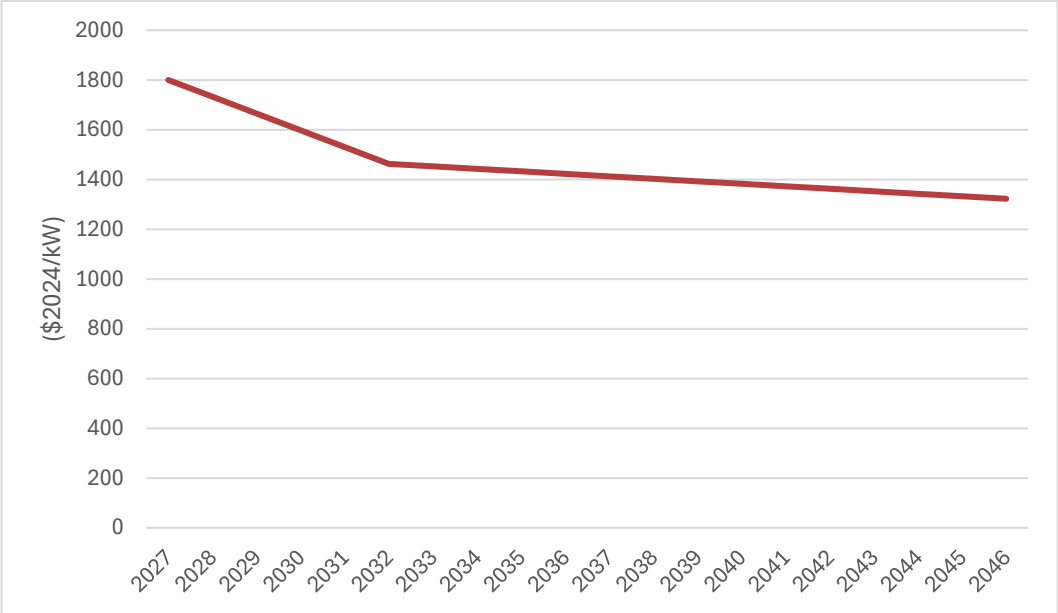


Figure G - 37 shows the same cost curve for batteries displayed in Figure G - 1 but on its own axis for a clearer view. Overnight capital costs over the course of the study deescalate to below $1400/kW over 20 years, with an especially steep decline over the first five years.

Summary Table

A summary of the Li-ion battery storage reference plant is captured in Table G - 20.

Table G - 20: Li-Ion Battery Storage Reference Plant Summary Table

Reference Plant	Utility Scale Lithium-Ion Battery Storage
Configuration	4-hour duration, lithium-ion battery
Year Available to Model	Start of study
Development/Construction Period (Years)	2
Roundtrip Efficiency	88%
Overnight Capital Cost ($/kW)	1800
Fixed O&M Cost ($/kW-yr)	38
Variable O&M ($/MWh)	0
Economic Life (years)	15

Solar Plus Battery

Co-locating renewables with storage helps avoid curtailment of energy, reduce integration costs, provide grid services, and reduce transmission costs by sharing a single point of interconnection. As both utility-scale solar PV, wind, and battery storage costs decline, opportunities to pair the resources together are gaining traction. The Ninth Power Plan includes a reference plant for a co-located solar PV plus battery storage system (also referred to as solar + storage).

There are two major technology configurations for co-located solar and battery: AC-coupled and DC-coupled. An AC-coupled system means that there are two inverters, one for the solar and one for the battery – equivalent to two distinct systems that are located at the same site. There are cost reductions in balance-of-system costs for this type of configuration, for example shared siting, land, interconnection, and fixed transmission costs. A DC-coupled system has only one inverter for both the solar and the battery. This configuration receives all the same balance-of-system benefits as the AC-coupled system, plus the reduced cost of one inverter instead of two. However, the major benefit of a DC-coupled system is that for solar projects with an inverter loading ratio greater than 1.0 (solar module capacity is overbuilt compared to the inverter capacity), instead of clipping the energy when it exceeds the maximum rating of the inverter, it can be directly transferred to the battery and stored for later use.

Availability

Solar + storage is available at beginning of study and takes two years to develop and construct. Like solar, the hybrid resource has an assumed 30-year economic life but that includes a battery replacement at year 15. The cost of that replacement is incorporated into the fixed O&M costs.

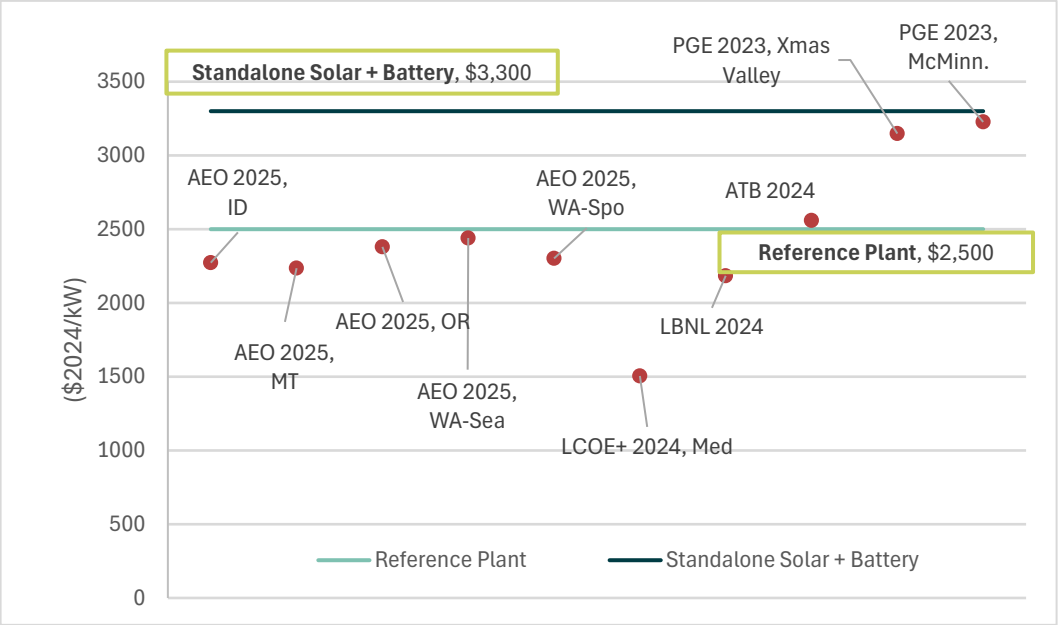
This hybrid resource reference plant was built up as a combination of the solar and the battery reference plants with paralleled characteristics as appropriate. For example, available locations and their accompanying production curves for the representative solar + storage resource are the same as the utility-scale solar reference plant. The battery charge and dispatch are based on that shape.

Costs

One of the benefits of co-locating storage and solar is the cost savings from shared equipment, particularly inverter cost savings. Additional savings are possible in land cost and some construction and development expenses, such as shared installation roads and equipment.

Figure G - 38 and Figure G - 39 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates.

Figure G - 38: Literature Review of Solar + Storage Overnight Capital Costs



The literature review of solar + storage overnight capital costs, seen plotted in Figure G - 38, coalesces around $2500/kW, shown by the light blue line. The dark blue line at $3300/kW is the cost of a standalone solar plant ($1500/kW) and a standalone battery ($1800/kW) combined, showing about a 25% savings from colocation. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 39: Literature Review of Solar + Storage Fixed Operations & Maintenance Cost

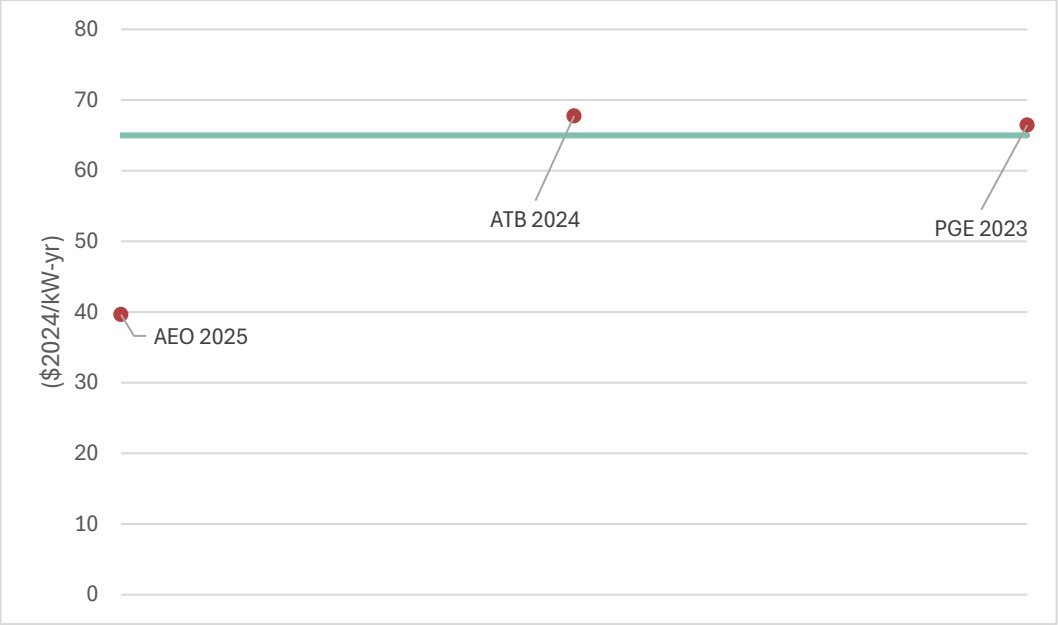


Figure G - 39 shows there is a clustering of solar + storage fixed operations and maintenance costs around $65/kW-yr. This number is inclusive of the cost of battery replacement halfway through the solar system's lifetime.

Figure G - 40: Forward Cost Curves for Solar + Storage Overnight Capital Costs

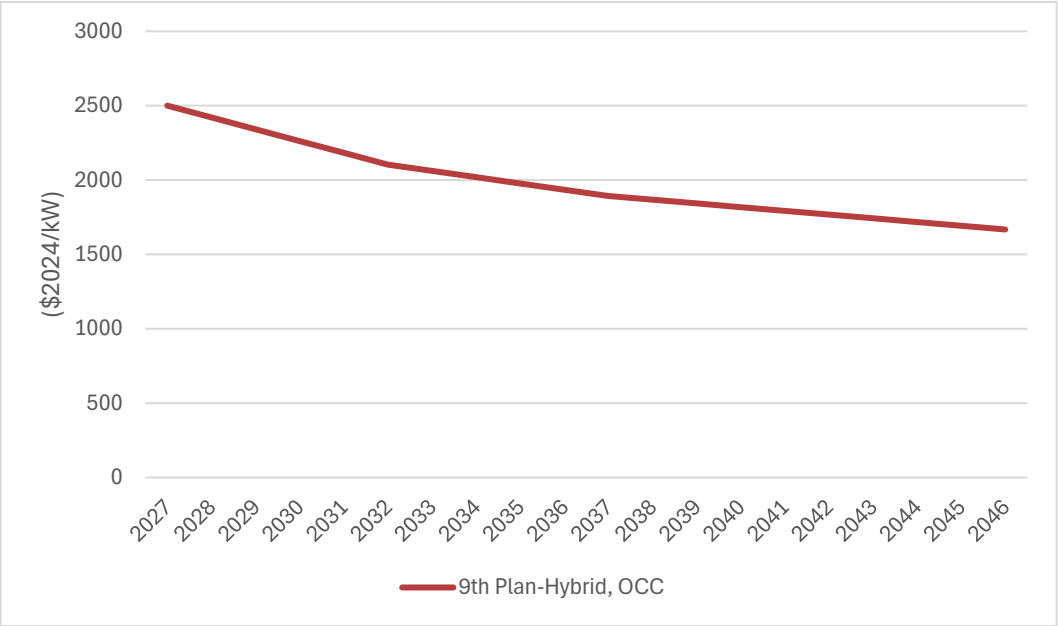


Figure G - 40 shows the same cost curve for solar + storage displayed in Figure G - 1 but on its own axis for a clearer view. Overnight capital costs over the course of the study deescalate to almost $1600/kW over 20 years.

Locational Cost Variation

Solar + storage mirrors the locational differentiation of utility-scale solar, as they are capturing the same renewable resource. More detail on that process is included in the utility-scale solar section and will not be replicated here. Those adjustments by zone are applied by location to the starting solar capital cost in Table G - 21.

Table G - 21: Locational Variation of Solar + Storage Capital Costs

	Variation	Solar + Storage, OCC
Starting Point	*n/a*	*$2500*
Northwest	1.0745	$2686.25
Central	1.025	$2563.25
East	1.001	$2502.50

Summary Table

The summary of the solar + storage reference plant is captured by Table G - 22.

Table G - 22: Solar + Storage Reference Plant Summary Table

Reference Plant	Solar + Battery Storage
Configuration	Solar Co-Located with DC-Coupled 4-hour Li-Ion Battery
Location	Available in all zones except for PSE Central
Year Available to Model	Start of study
Development/Construction Period (Years)	2
Capacity (MW)	1:1 pairing[71]
Capacity Factor/RTE	See shape (Solar) 88% RTE (Battery)
Overnight Capital Cost ($/kW)	2500
Fixed O&M Cost ($/kW-yr)	65
Variable O&M ($/MWh)	0
Economic Life (years)	30

[71] Like solar and battery, the model can select the hybrid resource continuously and so can be selected at any size, but the solar and the battery will be equivalent. So, for example, if a 100 MW solar resource is built, it would be paired with a 100 MW or 400 MWh battery.

Natural Gas

Natural gas turbine technologies are a proven and mature source of electricity generation. They also continue to adapt to the needs of the regional power system. As more variable energy resources have come online, it has become increasingly important for gas resources to provide flexibility (fast start, ramping abilities) and greater efficiency (less fuel is combusted to generate more electricity). There are two major types of natural gas resources that the Council assessed for the Ninth Power Plan: combined cycle combustion turbines (CCCT) and gas peakers (which include simple cycle combustion turbine (SCCT) technologies and reciprocating engines).

Simple Cycle

Gas peakers are generating units that can ramp up and down quickly to meet spikes in demand. Newer more flexible and efficient models can be used to follow the variable output of wind and solar resources. Because of the availability and abundance of hydropower, relatively few gas peakers have been constructed in the Northwest, compared to regions with a predominance of thermal electric capacity. In general, gas peakers produce electricity at a much lower capacity factor when compared to CCCTs, and run only when needed. However, over the last 20 years the region called on their gas peaker fleet more frequently, with average capacity factors increasing sharply since the early 2000s.

Simple-cycle gas turbines have been used for decades to help serve peak loads. A simple-cycle gas turbine generator plant consists of a combustion gas turbine (sometimes multiples) driving an electric power generator. The three primary simple cycle gas turbine technologies available today are frame, aeroderivative, and intercooled.

- **Frame** turbines are used for stationary power generation and are generally less expensive and more rugged and reliable than other simple cycle types. They are also traditionally less efficient with a higher heat rate and higher emissions.
- **Reciprocating Engine** generating units (Recips) are modular reciprocating engines that drive a generator. This design makes them particularly flexible and more efficient than other peaker technologies.
- **Aeroderivative** turbines are based on engines developed for aircraft propulsion and are characterized as light weight, highly efficient, and flexible. Aeroderivative are generally more expensive than frame turbines. As discussed above, this technology was not developed into a separate reference plant.

Combined Cycle

Combined cycle combustion turbines (CCCT) are highly efficient generating resources that can provide baseload and dispatchable power. A CCCT plant consists of one or more gas turbine generators each exhausting to a heat recovery steam generator (HRSG). The HRSG captures the exhaust heat and produces steam that is supplied to a steam turbine generator and condenser to produce additional electricity. The productive use of the gas turbine exhaust energy greatly increases the efficiency and output of CCCT plants as compared to simple-cycle gas turbines. This increasingly

versatile technology can be used both as a replacement to retiring baseload coal power, and as a complementary firming power source to hydropower and renewable generation. The high efficiency of combined cycle plants coupled with the low carbon content of natural gas fuel results in the lowest carbon dioxide production rate of any fossil fuel generating technology.

In the Northwest, operation of existing CCCT plants depends largely on the variability in annual hydro generation. During low water years, when hydro conditions are below average, thermal resources (primarily natural gas CCCT and coal units) tend to run at higher capacity factors to make up for the lower amount of hydroelectric power. During high water years, utilization of CCCT plants may decline. There are many other factors that may impact regional CCCT utilization, such as load, renewable power generation levels, plant outages, fuel prices, and wholesale electricity prices.

For more information about natural gas development in the region see Technical Appendix B – Existing System Parameters and Policies.

Availability

Natural gas resources are available at the beginning of the study. Combined cycles take four years of development and construction, simple cycle frame turbines take three years, and reciprocating engines take two years.

There are limitations to where natural gas plants can be built which are represented in the Council's modeling. Emitting resources, such as coal and natural gas, are regulated by clean policies,[72] which act as an intentional dampener on their future development. In the region, Oregon has a law that bans new gas plants in the state. While Washington doesn't explicitly ban natural gas, their escalating carbon tax and 100% clean target will limit a plant's useful life, making them potentially less financially viable.

An additional limiting factor is available pipeline access. While all resources are impacted by their access to transmission (a resource can't be built if there's no space for it to connect to the transmissions system), a gas plant must also have access to fuel by way of natural gas pipelines. Currently, the existing gas pipeline system faces significant constraints. These include capacity bottlenecks where, especially during the winter, the region operates at maximum capacity with little room for additional demand. While new infrastructure could provide more capacity, due to regulatory hurdles and other challenges, a large new expansion for the power system would be difficult to accomplish in the next few years. New gas plants have some ability to work within these constraints, but that access is not unlimited, and there is minimal pipeline capacity available today.

The Council has represented this limitation in two ways, both with an added cost associated with fuel firming and with a maximum build limit in the model. Council staff have estimated that within the action plan period, or the first 6 years of the study, an additional 3,000 MW of new gas plants in the

[72] More about polices and how they affect resource development can be found in Technical Appendix B—Existing System Parameters and Policies.

region are plausible, assuming the new plants include storage facilities and potentially participate in limited pipeline expansions.[73] After the action plan period that cap rises to 10,000 MW for the remainder of the study, with the assumption that a larger pipeline expansion could occur. Within both constraints, new gas also has additional fuel firming costs associated with connecting to a system that is essentially fully subscribed, which are discussed later in this section.

Unlike renewable resources, a gas plant's production is not particularly affected by where it is located. However, fuel costs vary across the region, and the reference plants have therefore been split into east and west to account for the gas price they have access to. The BPA modeling zones span the east and the west with access to both fuel prices, and so have been split into a third and final reference plant location. More on the Council's fuel price forecast can be found in Technical Appendix E – Fuels Forecasts.

Finally, gas plants do have capacity and efficiency considerations that differentiate between the turbine technologies. A combined cycle combustion turbine has a discrete size associated with the turbine technology that is not easily resized the way the resources described so far can be. Additionally, each turbine type has an associated heat rate or the power plant's thermal efficiency. This measure calculates the amount of energy required to generate one kilowatt-hour of electricity and represents how efficiently a plant converts fuel into electricity. Larger combined-cycle turbines are more efficient than the smaller simple-cycle turbines, and therefore have lower heat rates. The capacities and heat rates of each natural gas turbine technology were explored via literature review, and refined with the help of the Council's advisory committees. Those reviews are shown in Table G - 23, Table G - 24, and Table G - 25 below.

Table G - 23: Combined Cycle Combustion Turbine Operating Characteristics Literature Review

Source	Size (MW)	Heat Rate (Btu/MWh)
NLR's Annual Technology Baseline	727	6.33
	649	6.06
	992	6.18
Gas Turbine World-2024 Handbook	627	5.609
	1227	5.645
EIA's AEO 2025	627	6.266
	1227	6.226
PacifiCorp 2025 IRP	649	6.04
PGE 2023 IRP	407	6.561

[73] The Council discussed this assumption with regional industry stakeholders. Stakeholders noted that it was challenging to estimate an exact value for this cap, that the ability to site new gas would vary on location, and some stakeholders stressed that additional gas would be difficult to site without pipeline upgrades.

Idaho Power 2023 IRP	300	6.363
PSE 2023 Progress Report	727	6.624
Avista 2025 IRP	312	6.82
NorthWestern 2023 IRP	250	
Final Reference Plant	**500**	**6.25**

Table G - 24: Simple Cycle – Frame Peaker Operating Characteristics Literature Review

Source	Size (MW)	Heat Rate (Btu/MWh)
NLR's Annual Technology Baseline	233	9.72
Gas Turbine World-2024 Handbook	419	8.236
EIA's AEO 2025	419	9.142
PacifiCorp 2025 IRP draft	233	9.717
PGE 2023 IRP	227	10.042
Idaho Power 2023 IRP	170	9.717
Puget Sound Energy 2023 Progress Report	233	9.904
Avista 2025 IRP	180	10.04
Final Reference Plant	**250**	**9.50**

Table G - 25: Simple Cycle – Alternate Peaker Operating Characteristics Literature Review

Source	Qualifier	Size (MW)	Heat Rate (Btu/kWh)
PacifiCorp 2025 IRP (draft)	Aero x 4	211	9.447
Idaho Power 2023 IRP	Recip	50	8.699
Puget Sound Energy 2023 Progress Report	Recip	21.4	8.445
Avista 2025 IRP	Recip	185	8.19
NorthWestern 2023 IRP	Aero	50	
	Recip	18	
Final Reference Plant	**Recip**	**100**	**8.50**

Costs

Overnight Capital and O&M Costs

The figures below show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates. Specifically overnight capital costs for combined cycle combustion turbines (CCCTs), frame simple cycle combustion turbines (SCCT-Frame) and alternative simple cycle combustions turbines (SCCT-Alt) are captured by Figure G - 41, Figure G - 42, and Figure G - 43 respectively. Fixed O&M costs are in Figure G - 45, and Figure G - 46.Variable Operations and Maintenance (O&M) costs for CCCTs and both types are SCCTs are show in Figure G - 47, Figure G - 48, and Figure G - 49.

The literature reviews of natural gas plant overnight capital costs are seen plotted in Figure G - 41 through Figure G - 43. In each figure, different source costs can be seen clustering around a median, represented by the light blue line. For CCCTs that middling cost is $1500/kW, SCCT-Frame costs group around $1000/kW, and the more expensive simple cycle plants costs collect around $1800/kW. These final costs are not pure averages of available data, or a simple eyeballing of the plots, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 41: Literature Review of Combined Cycle Combustion Turbine Overnight Capital Costs

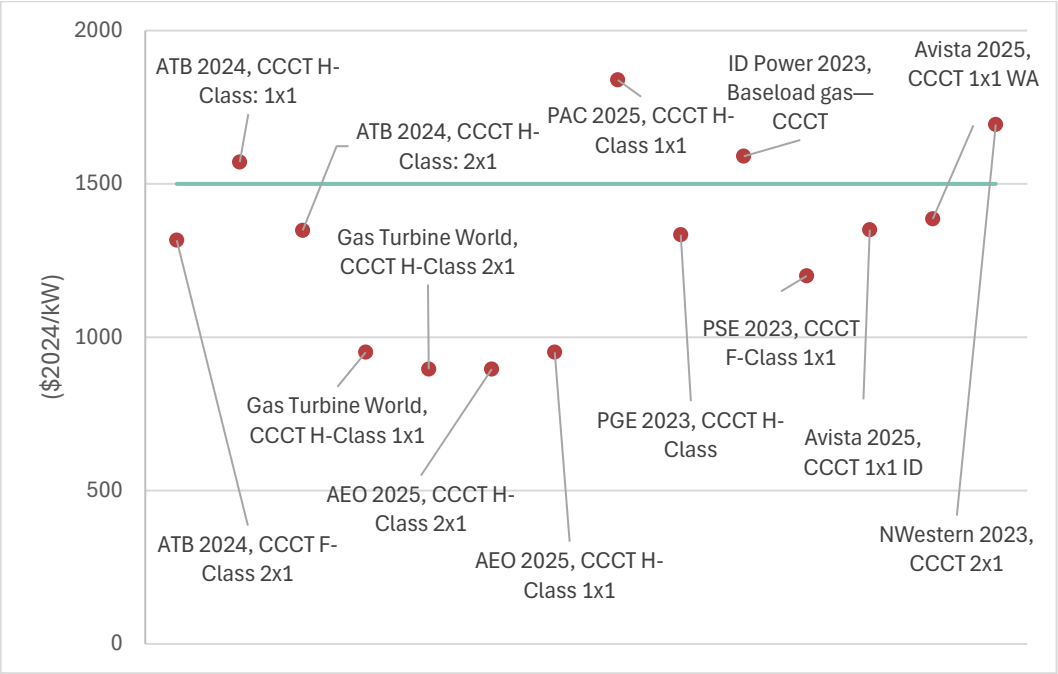


Figure G - 42: Literature Review of Frame Simple Cycle Combustion Turbine Overnight Capital Costs

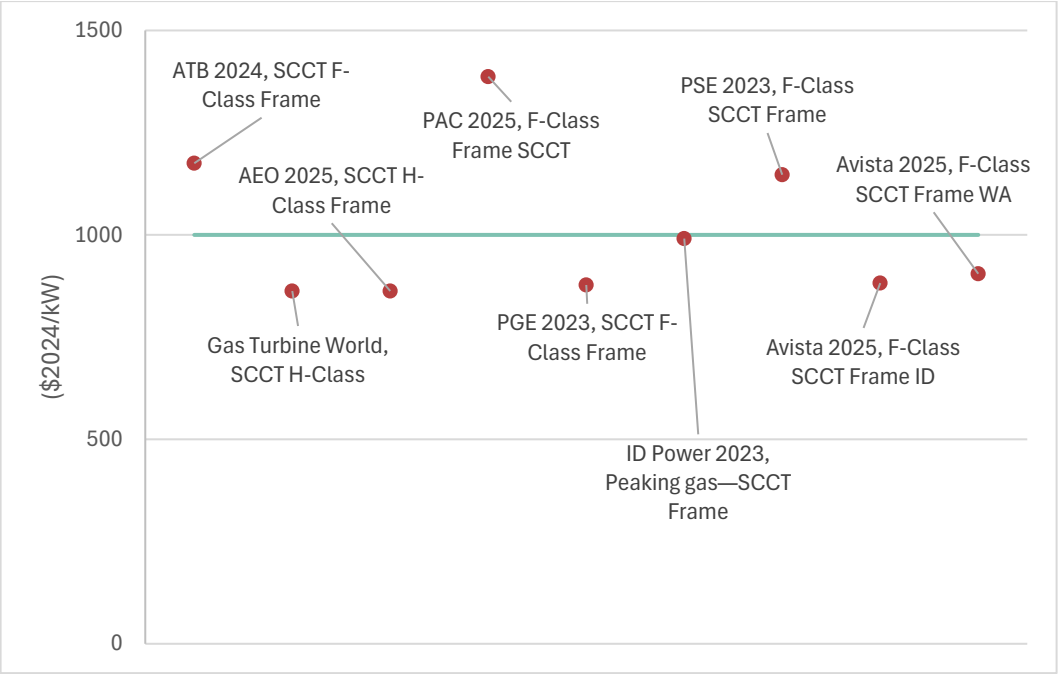


Figure G - 43: Literature Review of Alternative Simple Cycle Combustion Turbine Overnight Capital Costs

Like overnight capital costs, a literature review of fixed operations and maintenance costs for natural gas plants was performed and plotted. Costs for CCCTs, Frame SSCTs, and Alternative SCCTs can be seen grouping around $28/kW-yr, $16/kW-yr, and $17/kW-yr respectively. Applying the firming fuel

cost adder discussed in the section above raises those costs to $58/kW-yr for CCCTs, $21/kW-yr and $22/kW-yr for Frame and Recip SSCTs.

Figure G - 44: Literature Review of Combined Cycle Combustion Turbine Fixed Operations & Maintenance Costs

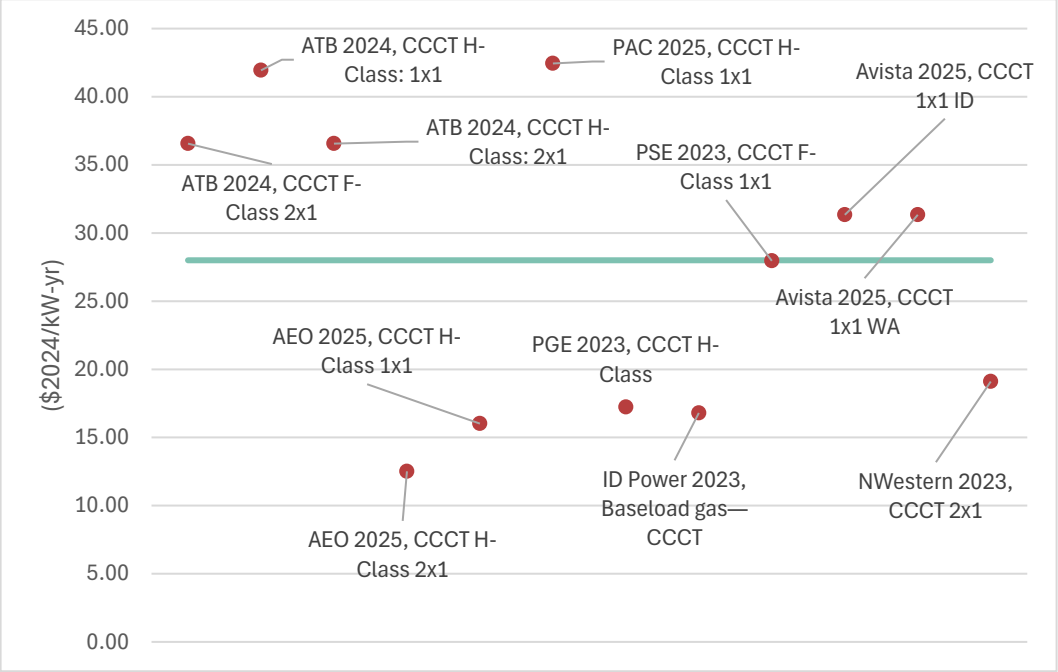


Figure G - 45: Literature Review of Frame Simple Cycle Combustion Turbine Fixed Operations & Maintenance Costs

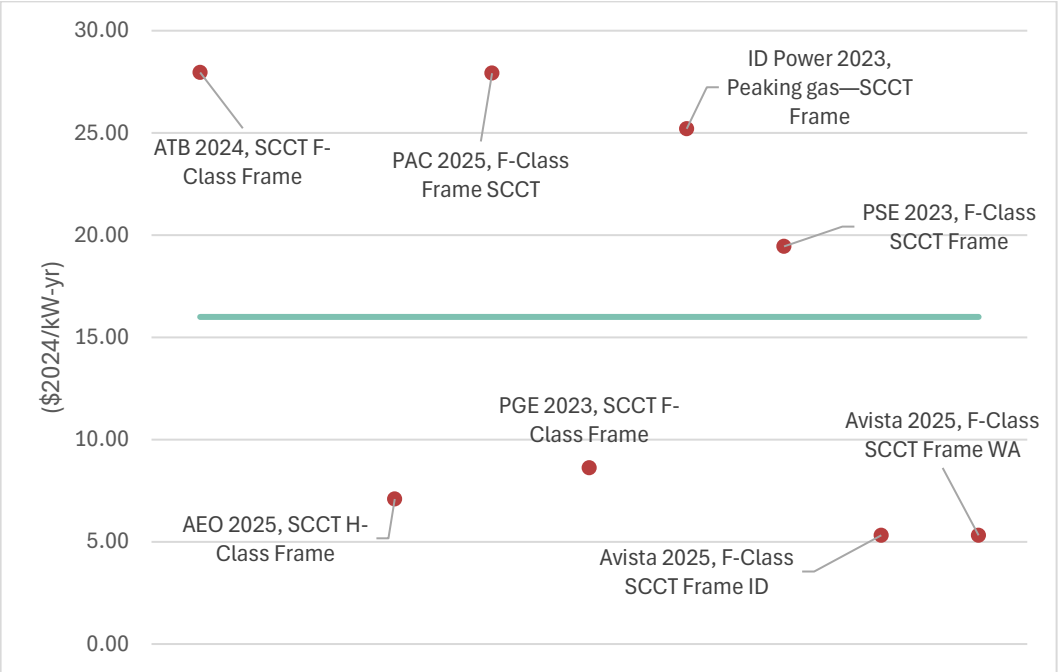
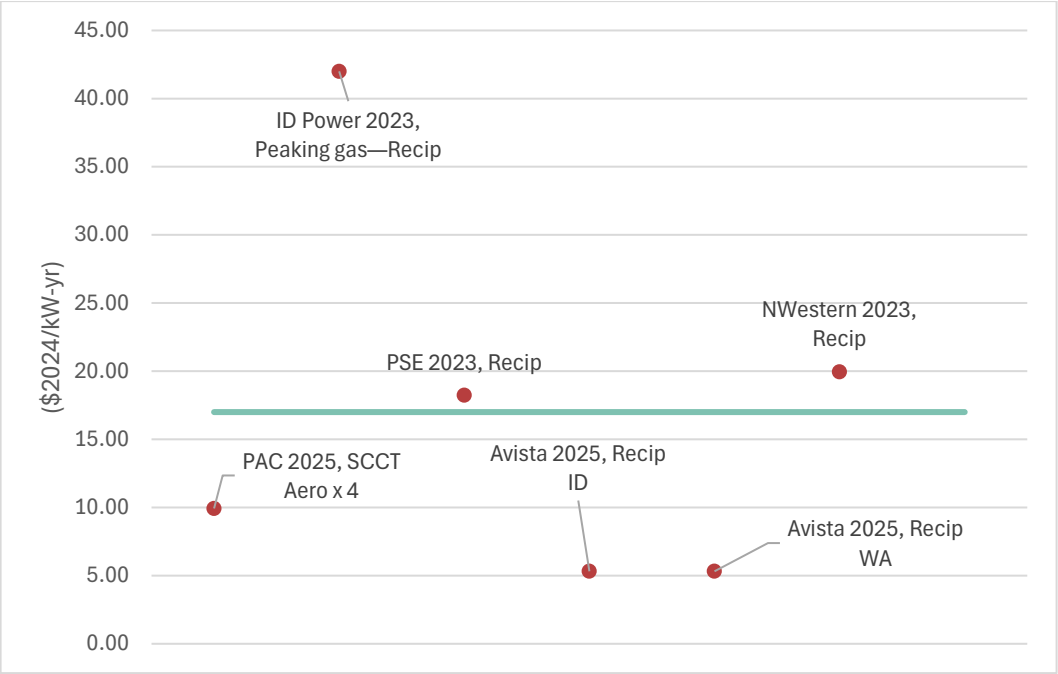


Figure G - 46: Literature Review of Alternative Simple Cycle Combustion Turbine Fixed Operations & Maintenance Costs



Unlike renewable resources, natural gas plants, in addition to fixed O&M costs, accrue *variable* O&M costs as a function of the amount of power they produce. This includes consumables such as water, chemicals, lubricants, catalysts, and waste disposal but does not include fuel costs. Because these costs are generation dependent, the values are levelized by the cost per unit of energy generation and presented in $/MWh.

As with other costs, a literature review of variable operations and maintenance costs for natural gas plants was performed and plotted. Costs for CCCTs, Frame SSCTs, and Alternative SCCTs can be seen grouping around $4/MWh, $3.50/MWh, and $5/MWh respectively.

Figure G - 47: Literature Review of Combined Cycle Combustion Turbine Variable Operations & Maintenance Costs

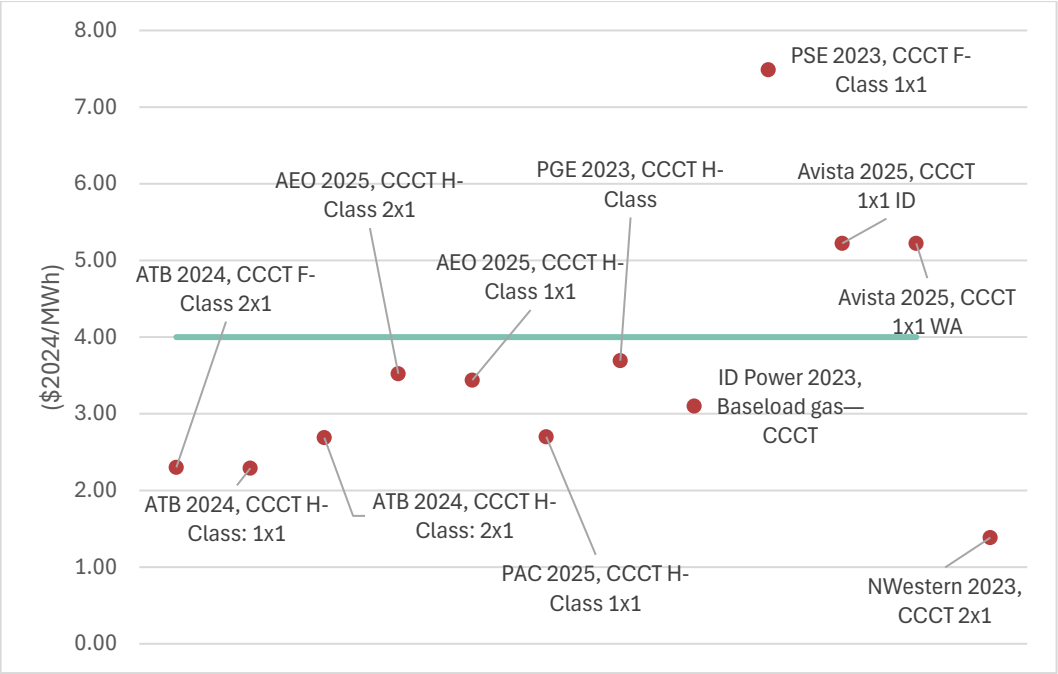


Figure G - 48: Literature Review of Frame Simple Cycle Combustion Turbine Variable Operations & Maintenance Costs

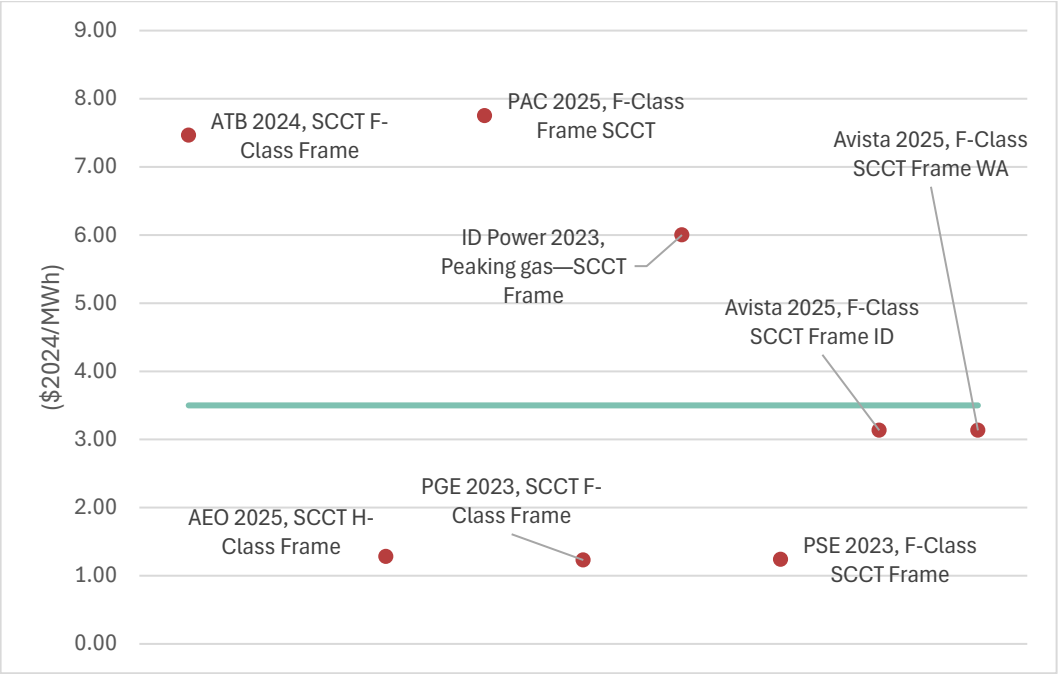


Figure G - 49: Literature Review of Alternative Simple Cycle Combustion Turbine Variable Operations & Maintenance Costs

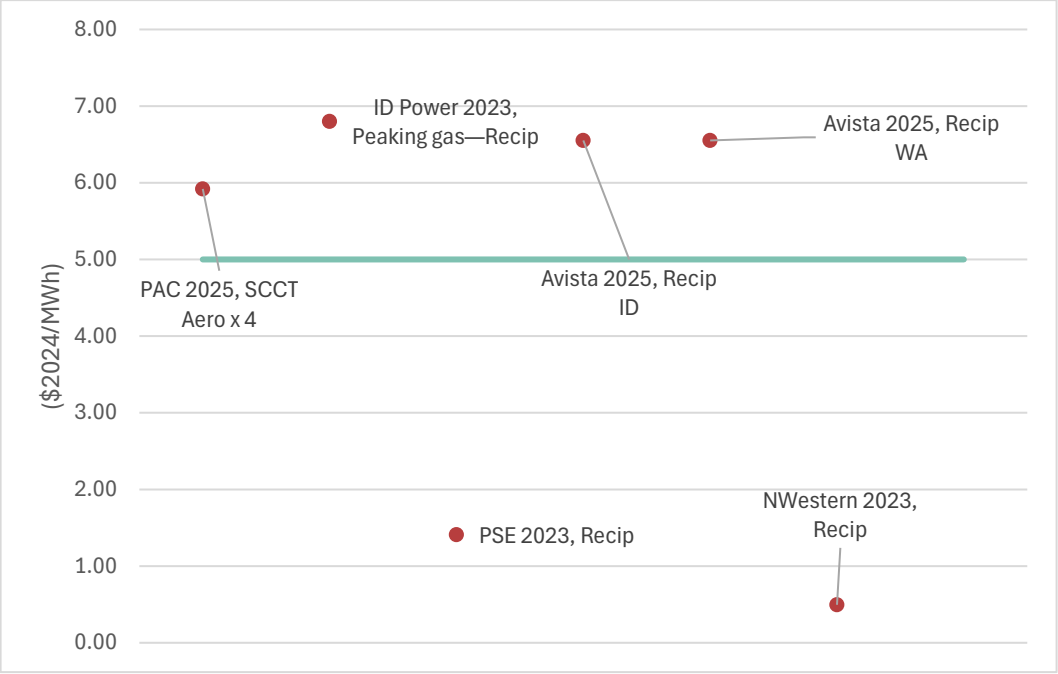


Figure G - 50: Forward Cost Curves for Gas Turbine Overnight Capital Costs

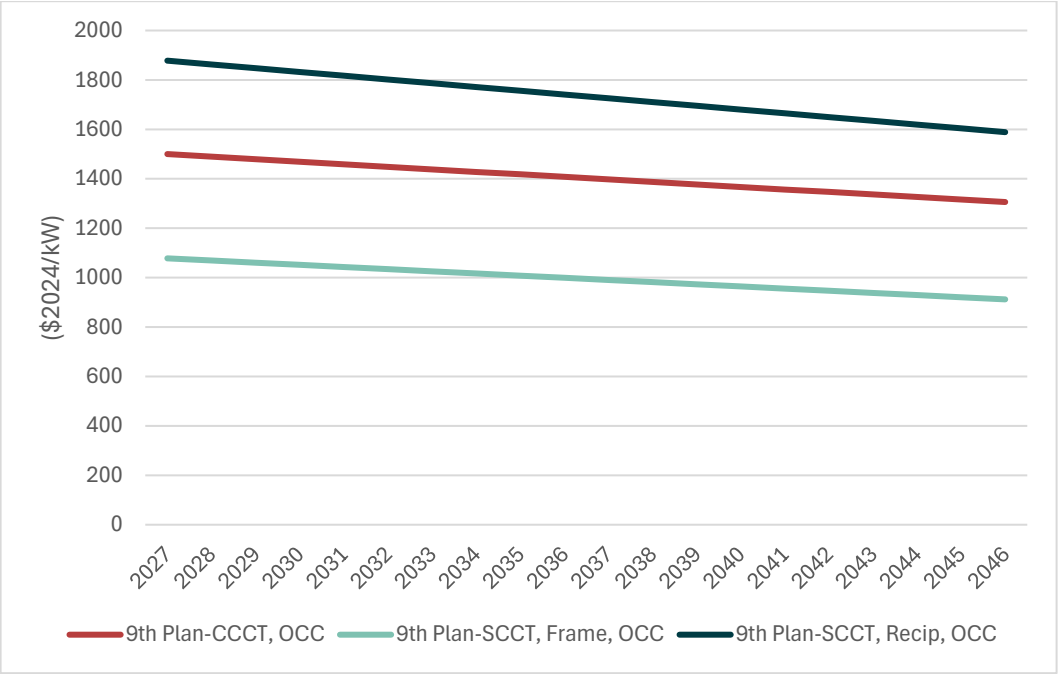
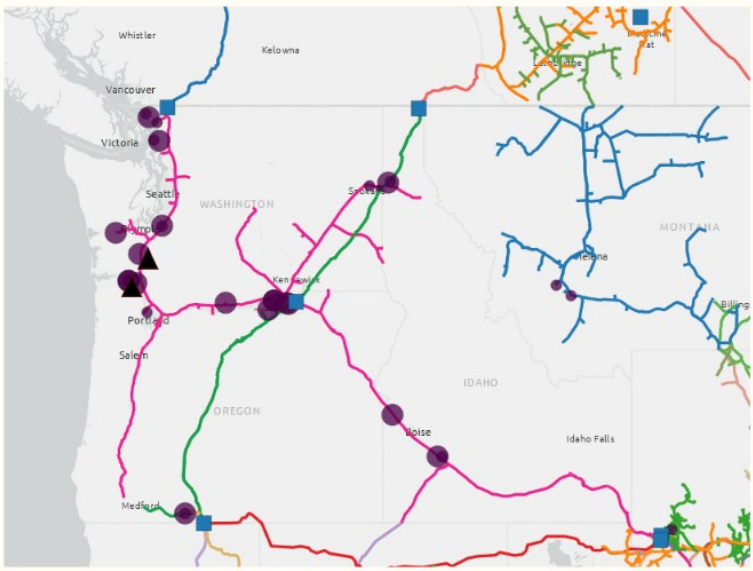


Figure G - 50 shows the same cost curves for natural gas plants displayed in Figure G - 1 applied to each type of natural gas plant included in the Ninth Plan and on its own axis for a clearer view. Overnight capital costs over the course of the study decrease by about 15% for combined cycle combustion turbines and almost 20% for the simple cycle turbines over 20 years.

Firming Fuel Cost Adder

The major pipelines in the Northwest (in Figure G - 51: Williams NWP in pink, and Gas Transmission Northwest in green) are running at high utilization rates, particularly at peak, with little to no firm gas contracts available. Considering that reality, and in alignment with what gas utilities are planning in their IRPs and seeing in their RFPs, a price adder for new gas plants is included to account for the firming of fuel supply.

Figure G - 51: Major Northwest Gas Pipeline



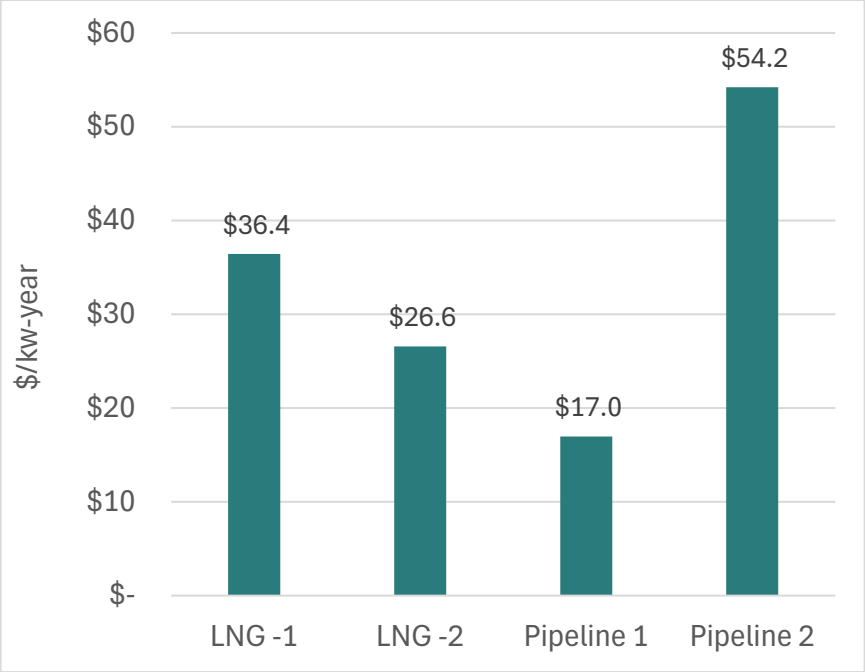
Firming Fuel Cost Adder - Simple Cycle Combustion Turbine – Fuel Oil Tank

Lower capacity gas plants (i.e. reciprocating engines and frame simple cycle combustion turbines) are small enough and run infrequently enough that a fuel tank and 48 hours of fuel a year provides sufficient backup for any peak event where pipeline access is not available. The 48 hours of fuel should be sufficient for most interruptions – with the plant coming down at night to stretch fuel for about three days of run-time. This results in a slight increase in capital costs (+$78/kW) and fixed operations and maintenance costs (+$5/kW-year)

Firming Fuel Cost Adder - Combined Cycle Combustion Turbine – Pipeline Upgrade/LNG peak shaving

Larger capacity gas plants (namely CCCT) require more fuel than a tank could realistically provide. As backup for these plants, two possible solutions were considered: a pipeline upgrade and liquified natural gas peak shaving. Both options would provide a gas plant with access to fuel when pipeline utilization is at its peak that they wouldn't otherwise have without a firm contract. These firming solutions are seen in utility planning and actual applications, and therefore are used to inform cost estimates. As with all reference plant decisions, the goal is a general price adder, acknowledging that the best solution for firming that supply will differ by utility situation and gas plant location.

Figure G - 52: Costs of Different Gas Firming Methodologies



Discussions with regional experts suggested that the low pipeline costs, shown in Figure G - 52, are no longer available as a means to firm a gas plant's fuel supply. Simpler and easier upgrades like compressor upgrades and software changes have already been implemented at most plants. Advisory committee members recommended those very low pipeline costs be discounted when coming up with a final cost. The best estimate, with the support of these experts, was an additional cost of $30/kW-year to be added to the fixed O&M cost of a CCCT.

The final costs of including the fuel supply firm gas adder to all gas technologies are summarized in Table G - 26.

Table G - 26: Final Gas Plant Costs Including Firming Cost Adder

Turbine Type	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
SCCT-Frame	$1000	$16	NA
SCCT-Frame: Adder	$78	$5	NA
SCCT-Frame: Total	**$1078**	**$20**	**$3.50**
SCCT-Recip	$1800	$17	NA
SCCT-Recip: Adder	$78	$5	NA
SCCT-Recip: Total	**$1878**	**$21**	**$5**
CCCT	NA	$28	NA
CCCT: Adder	NA	$30	NA

Turbine Type	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
CCCT: Total	**$1500**	**$58**	**$4**

Locational Cost Variation

The Council used locational cost adjustments aligning with the three zones created for fuel costs. The location groupings are chosen agnostic to the adjustment factors and so there is some work behind aligning the factors provided by the EIA, described in Table G - 3, to the locations selected for the natural gas reference plants. Which adjustment factor is applied to which reference plant is described in Table G - 27, where an eastside gas plant is given the average of Spokane, Great Falls, and Boise's cost adjustments, westside is given Portland and Seattle's, and BPA is given an average of the east and west side. Those adjustments are applied by location to the starting natural gas plant capital cost in Table G - 28.

Table G - 27: Natural Gas Plant Locational Cost Variation by Resource Cluster

	Locations	Cost Variation Multiplier	
		Combined Cycle	Simple Cycle
Eastside	Spokane, Great Falls, Boise	1.0102	1.0097
Westside	Portland, Seattle	1.1255	1.1200
BPA	Eastside/Westside	1.0679	1.0648

Table G - 28: Locational Variation of Natural Gas Plant Capital Costs

	Combined Cycle			Simple Cycle	
	Variation	**CCCT, OCC**	**Variation**	**Frame, OCC**	**Recip, OCC**
Starting Point	*n/a*	*$1500*	*n/a*	*$1078*	*$1878*
Westside	1.1255	$1688.25	1.120	$1207.36	$2103.36
Eastside	1.0102	$1515.30	1.0097	$1088.42	$1896.15
BPA	1.0679	$1601.78	1.0648	$1147.89	$1999.76

Summary Table

The summary of the natural gas reference plants is captured by Table G - 29.

Table G - 29: Natural Gas Reference Plant Summary Table

Reference Plant	CCCT H-Class 1x1	SCCT-Frame	SCCT-Reciprocating Engine
Configuration	1x1	1x__	__x18
Location	IPCO, BPA IDMT, NWMT, AVA, PSE Olympia, BPA WA	IPCO, BPA IDMT, NWMT, AVA, PSE(Olympia, Central, North), BPA WA	
Year Available to Model	Beginning of Study		
Development/Construction Period (Years)	4	3	2
Capacity (MW)	500	250	100
Heat Rate (Btu/kWh)	6250	9500	8500
Overnight Capital Cost ($/kW)	$1500	$1078	$1878
Fixed O&M Cost ($/kW-yr)	$58.00	$21.00	$22.00
Variable O&M ($/MWh)	$4.00	$3.50	$5.00
Economic Life	30 years		

Limited Availability Resources

Resources designated limited availability are commercially available resources with limited development potential in the region. These resources are given a mix of qualitative and some quantitative analysis. These resources are assigned a harder availability limit based on their physical constraints in the region. The reference plants created for limited availability resources in the Ninth Plan include conventional geothermal, offshore wind, and pumped storage.

Conventional Geothermal

Conventional geothermal is a renewable, clean energy resource with zero or low carbon emissions. The amount of emissions depend on the technology used, with flash steam technology emitting minimal excess steam and dry steam and binary cycle having zero emissions. The region has a significant, naturally occurring geothermal resource, especially in Southern Oregon and Idaho, but development has been limited. Conventional geothermal is a resource that requires the natural occurrence of heat, water, and permeability beneath the earth's surface. This combination makes development costly and uncertain. There has been recent development in geothermal technology that may reduce the cost and risk of the resource, but it is unproven on a commercial scale. Further discussion of enhanced geothermal technology is available in the emerging technology section of this appendix.

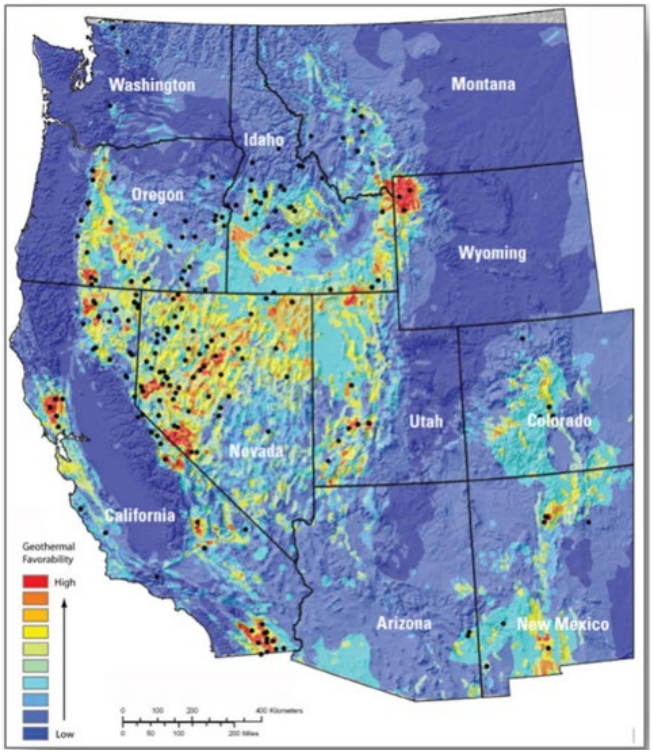
Availability

The Council considers geothermal a limited resource due to its highly site-specific nature. The USGS geothermal potential assessment, with some allowances for undiscovered potential, was used to inform an estimate of about 462 MW of conventional geothermal potential in the region, specifically Oregon and Idaho .[74] Figure G - 53 shows the areas that are favorable for geothermal, with the warmer colors indicating more favorable areas. More on the geothermal resource in the region can be found in Technical Appendix B – Existing System Parameters and Policies.

Geothermal is available at the beginning of study but has one of the longest development and construction timelines of 7 years, due to its extended and potentially fruitless exploration period.

Both the geothermal resource's capacity factor and its net capacity are based on the assumptions in NLR's ATB.[75] The Council's geothermal reference has a capacity factor of 80% and a discrete capacity of 30 MW.

Figure G - 53: Map of Geothermal Favorability in the West[76]

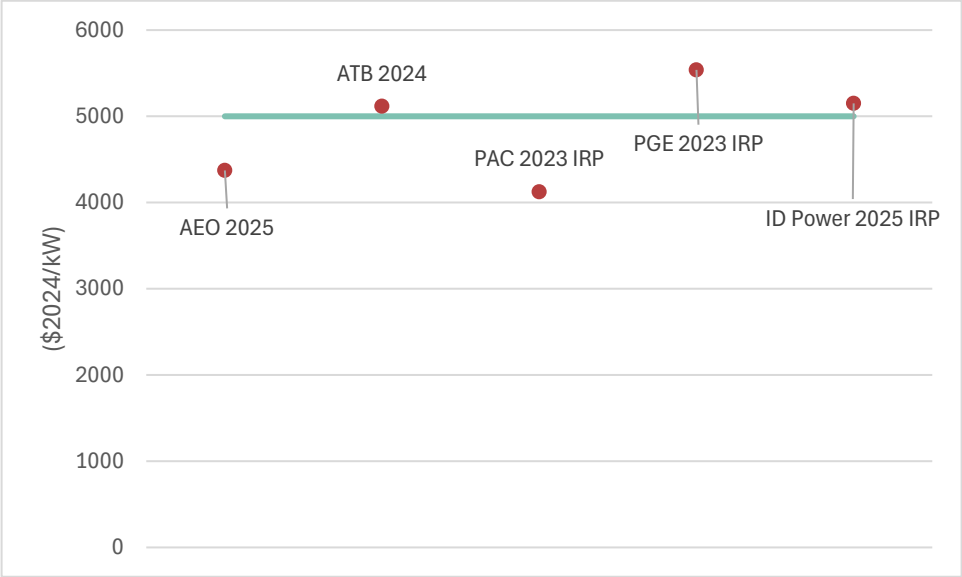


[74] USGS assessment of geothermal resources: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[75] https://atb.nrel.gov/electricity/2024/geothermal.
[76] https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf: Map of favorability of occurrence for geothermal resources in the western US. Warmer colors equate with higher favorability. Identified geothermal systems are represented by black dots.

Costs

Figure G - 54 and Figure G - 55 show the data plots and analysis that were used to develop the Ninth Power Plan geothermal reference plant cost estimates.

Figure G - 54: Literature Review of Conventional Geothermal Overnight Capital Costs



The literature review of conventional geothermal overnight capital costs, seen plotted Figure G - 54, coalesce around $5000/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Similarly, Figure G - 55 shows there is a clustering of geothermal fixed operations and maintenance costs around $130/kW-yr.

Figure G - 55: Literature Review of Conv. Geothermal Fixed Operations & Maintenance Costs

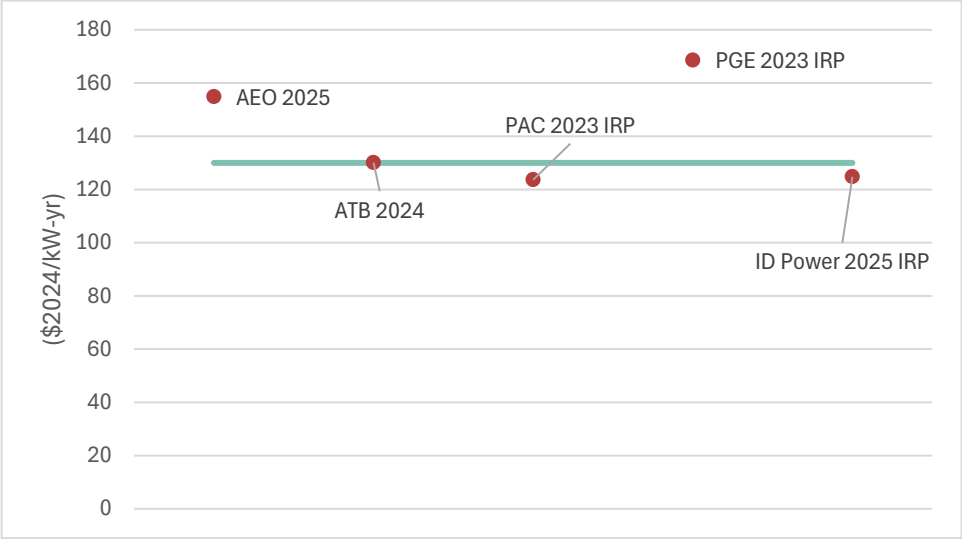


Figure G - 56: Forward Cost Curves for Conventional Geothermal Overnight Capital Costs

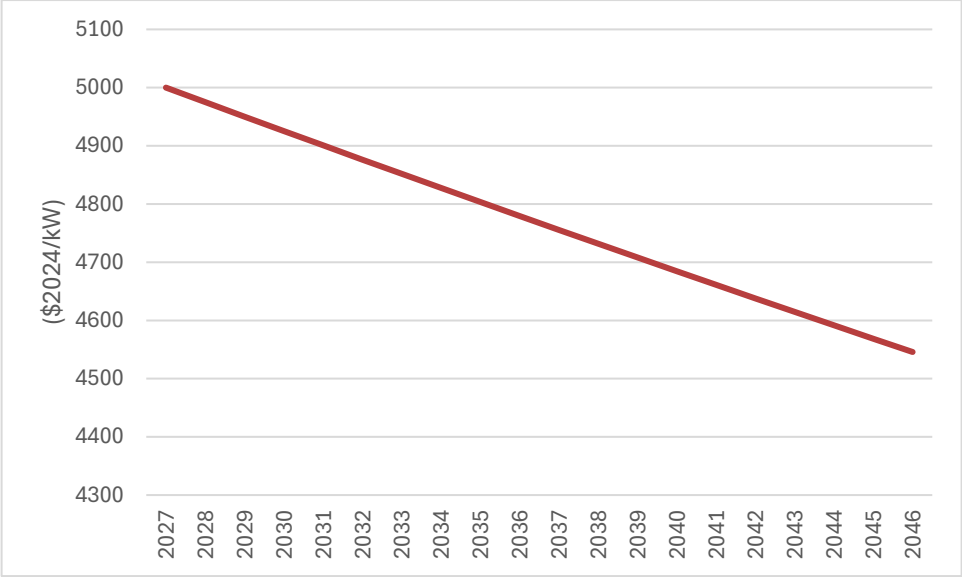


Figure G - 56 shows the NLR cost curve for geothermal. Overnight capital costs over the course of the study deescalate to below $4600/kW over 20 years.

Summary Table

The summary of the conventional geothermal reference plant is captured by Table G - 30.

Table G - 30: Conventional Geothermal Reference Plant Summary Table

Reference Plant	Conventional Geothermal
Configuration	Binary, Closed loop
Location	East of the Cascades (OR/ID)
Available Date	2024
Development/Construction Period (Years)	7
Capacity (MW)	30 (net)
Avg Capacity Factor	80%
Overnight Capital Cost ($/kW)	$5,000
Fixed O&M Cost ($/kW-yr)	130
Variable O&M ($/MWh)	0
Economic Life (years)	30
Maximum Buildout	462 MW (22 plants)

Offshore Wind

While offshore wind is an established resource in other parts of the world, it is still emerging in the Pacific Northwest. Offshore wind turbines are like their onshore counterparts, except that they tend to be much larger in size and energy output. A typical onshore wind turbine installed today is about 3 MW, while an offshore wind turbine is closer to 10 MW. There are multiple turbine technologies that can be used, depending on the area and depth of the body of water. In shallow waters, a fixed-bottom turbine can be deployed, where the device is installed and connected to a foundation in the seabed (or floor of another body of water). Once the water depth gets to around 60 meters and greater, a fixed-bottom installation is no longer feasible. Instead, a floating turbine is required – a turbine that sits atop a floating platform that is tethered to the seabed to prevent it from drifting. Floating turbine technologies are less well established than fixed-bottom, but they open up significantly more potential for offshore wind in terms of access to more viable wind speed sites.

Availability

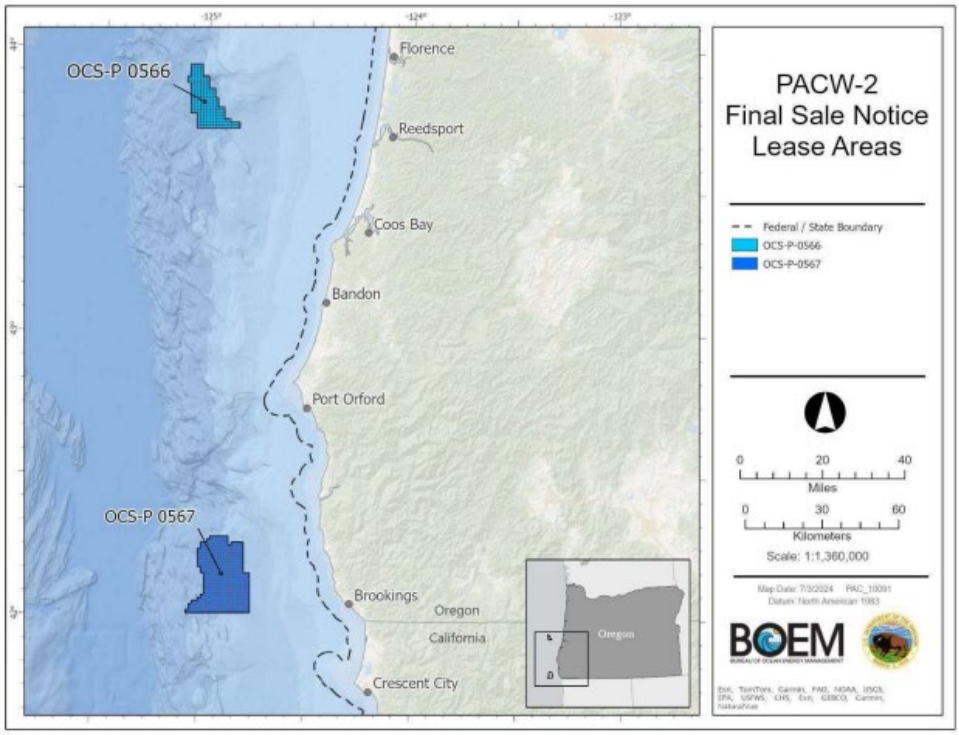
Offshore wind is only available in federally designated leasing areas; two such areas have been identified in the region off the Oregon Coast near Coos Bay and then further south near Brookings, shown on the map in Figure G - 57. The Coos Bay lease area has a capacity of 991 MW and Brookings is 2,166 MW for a total offshore wind capacity of about 3GW in the region. More description by lease area can be found in Table G - 31 below.

The latest estimates of timing from Bureau of Ocean Management (BOEM) have the earliest online dates for offshore wind plants in either of those lease areas at 2032. However, the Council ultimately used a more conservative assumption of 2035 based on increased uncertainty from federal policy changes.

Table G - 31: Oregon Lease Area Descriptive Statistics

Lease Area	Acres	Installation Capacity	Minimum Depth	Maximum Depth	Closest Dist. to Shore
Brookings OCS-P 0567	133,792	2,166 MW	567 m	1,531 m	18 miles
Coos Bay OCS-P 0566	61,203	991 MW	635 m	1,414 m	32 miles
Total	194,995	3,157 MW	--	--	--

Figure G - 57: Map of Offshore Wind Final Lease Areas[77]

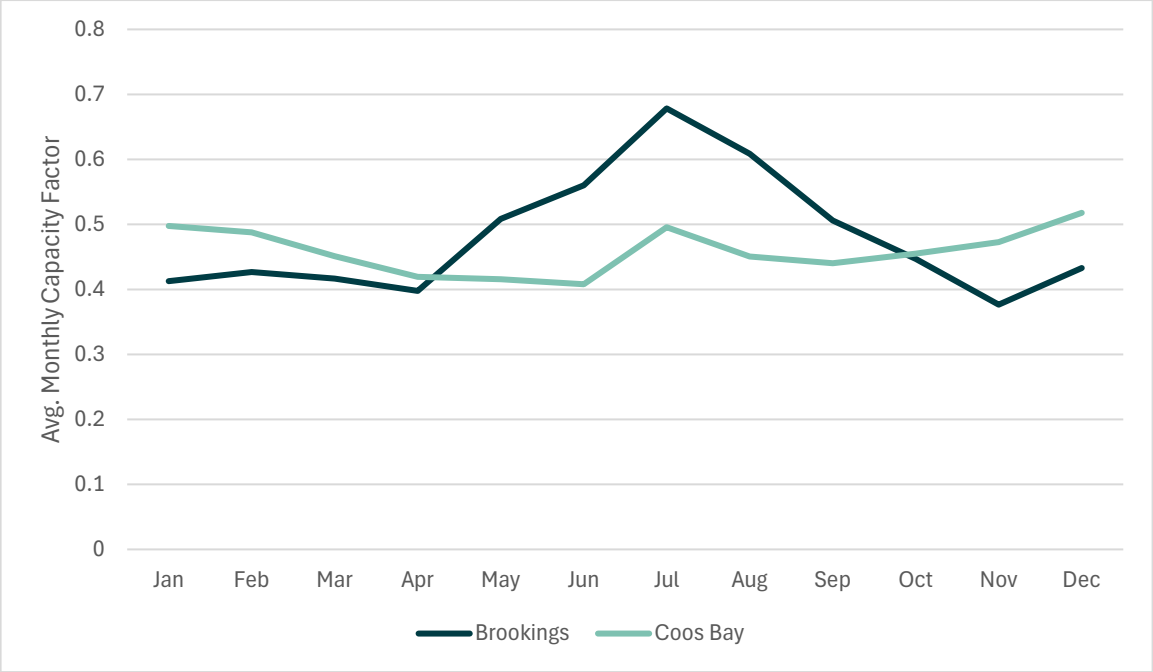


Generation Shapes

Like other renewable resources, offshore wind locations have associated capacity factors based on synthetic wind generation profiles. Development of the weather profiles and resulting generation are discussed with more detail in Technical Appendix D – Climate Model Data and Assumptions Similar to onshore wind, synthetic future generation curves were generated for every hour of every day for each lease area for the whole study. Figure G - 58 shows the average of monthly capacity across a year to illustrate the general variation in shape between the call zones. The annual generation shapes also illustrate the difference between onshore and off-shore wind. Off-shore wind has an average capacity factor of around 50% while onshore wind is perhaps less consistent than the off-shore resource and averages around 30-40% depending on the location.

[77] OCS-P 0566 refers to Coos Bay call area. OCS-P 0567 refers to Brookings call area on the map. BOEM final sale notice decision memorandum: https://www.boem.gov/sites/default/files/documents/renewable-energy/state-activities/Oregon%20FSN%20Decision%20Memo%20PACW2_0.pdf.

Figure G - 58: Average Monthly Offshore Wind Capacity Factors at Regional Call Areas



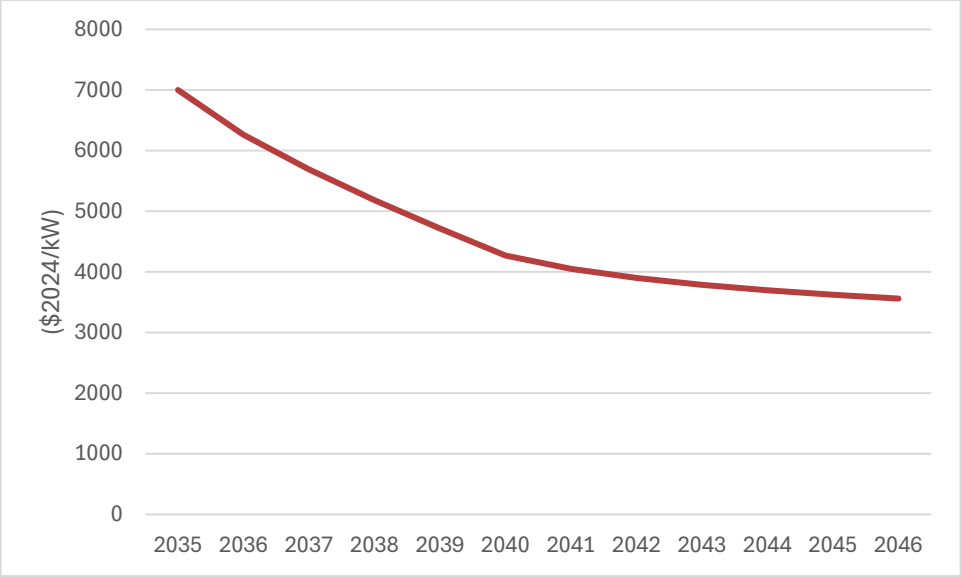
Cost

The final costs for the offshore wind reference plant are primarily informed by the NLR Annual Technology Baseline.[78] The Council chose this source since floating offshore wind does not yet exist in the US, and NLR is the primary resource for much of the existing offshore wind development research. This same source is used by many others in their planning of offshore wind. The overnight capital cost of $7000/kW and a fixed O&M of $100/kW-yr rely on NLR as the source.

NLR's cost curve for offshore wind is displayed in Figure G - 59. Overnight capital costs over the course of the study deescalate to just below $4000/kW over 20 years, with a steeper curve over the first five years.

[78] https://atb.nrel.gov/electricity/2024/offshore_wind.

Figure G - 59: Forward Cost Curve for Offshore Wind Overnight Capital Costs



Summary Table

The summary of the conventional geothermal reference plant is captured by Table G - 32.

Table G - 32: Offshore Wind Reference Plant Summary Table

Reference Plant	Offshore Wind
Configuration	15MW turbine, 248-meter rotor diameter, 150-meter hub height, semisubmersible (floating technology)
Location	Brookings call area Coos Bay call area
Availability Date	2035
Development Period (Years)	5
Construction Period (Years)	3
Capacity Factor	~50%
Overnight Capital Cost ($/kW)	$7,000
Fixed O&M Cost ($/kW-yr)	$100
Variable O&M ($/MWh)	0
Economic Life (years)	30
Maximum Buildout	3 GW

Pumped Storage

Pumped storage hydropower is an established and commercially mature energy storage resource, but there has been limited development in the Pacific Northwest to date. A typical project consists of an upper reservoir and a lower reservoir connected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower reservoir to the upper reservoir and generated by releasing water from the upper reservoir through the turbines to the lower reservoir. Most existing pumped-storage projects were designed to shift energy from off-peak hours or low demand periods to times of peak demand. Advances in technology have made it possible for pumped storage to better provide capacity, frequency regulation, voltage and reactive support, load following, and longer-term shaping of energy from variable resources. These improvements include shifting to adjustable variable speed pumps rather than fixed speed pumps and employing ternary units that allow the turbine and pump to operate simultaneously.

Availability

Pumped storage projects require suitable topography and geologic conditions for either constructing upper and lower reservoirs at significantly different elevations within close proximity, or for taking advantage of naturally occurring water flows and existing/natural reservoirs. In addition, a nearby water supply is required for initial reservoir charge and occasional replenishment for losses due to evaporation. The Council developed 10 reference plants totaling 4000 MW of potential, based on the projects currently in development in the region and what is realistically achievable over the next two decades. Figure G - 60 shows the planned locations in the region that informed these reference plants and Table G - 33 provides more information on the specific projects.

As a storage resource, pumped storage has a round-trip efficiency, which is again the ratio of energy discharged to the grid to the energy received from the grid to bring the storage system to the same state of charge. Pacific Northwest National Laboratory (PNNL) identified a range of RTEs for pumped storage resources of 70%-87%.[79] The Council selected a middle estimate of 80% RTE, in alignment with NLR's ATB.[80]

[79] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf.
[80] https://atb.nrel.gov/electricity/2024/pumped_storage_hydropower.

Figure G - 60: Map of Planned and Operating Pumped Storage Resources in the Region[81]

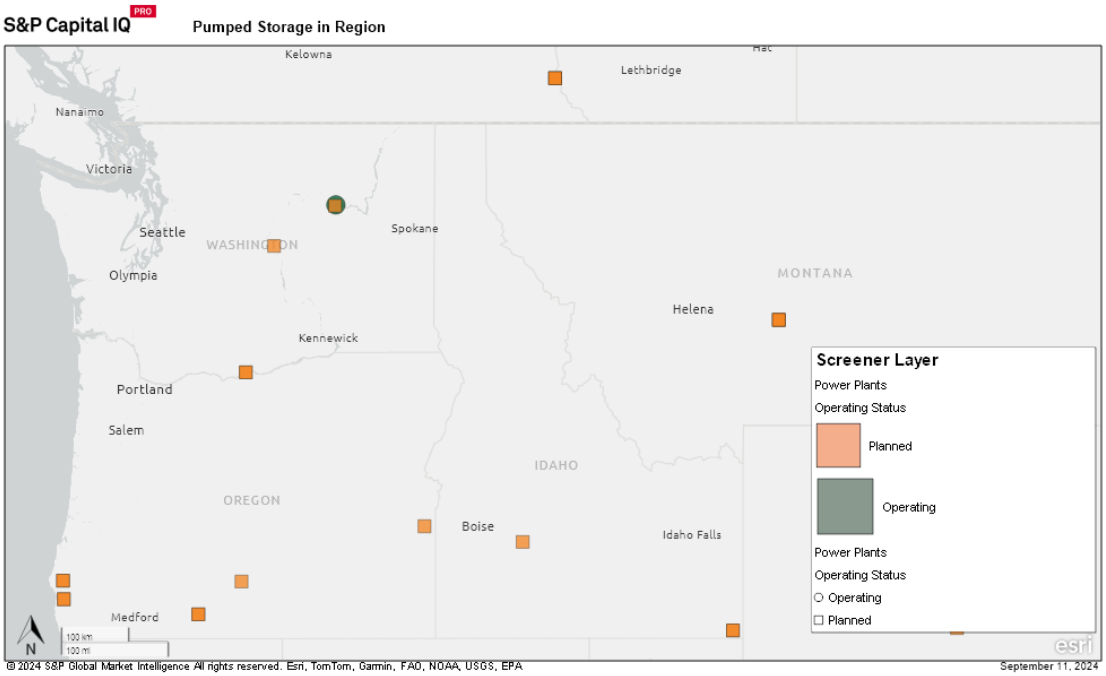


Table G - 33: Location and Capacity of Planned Regional Pumped Storage[82]

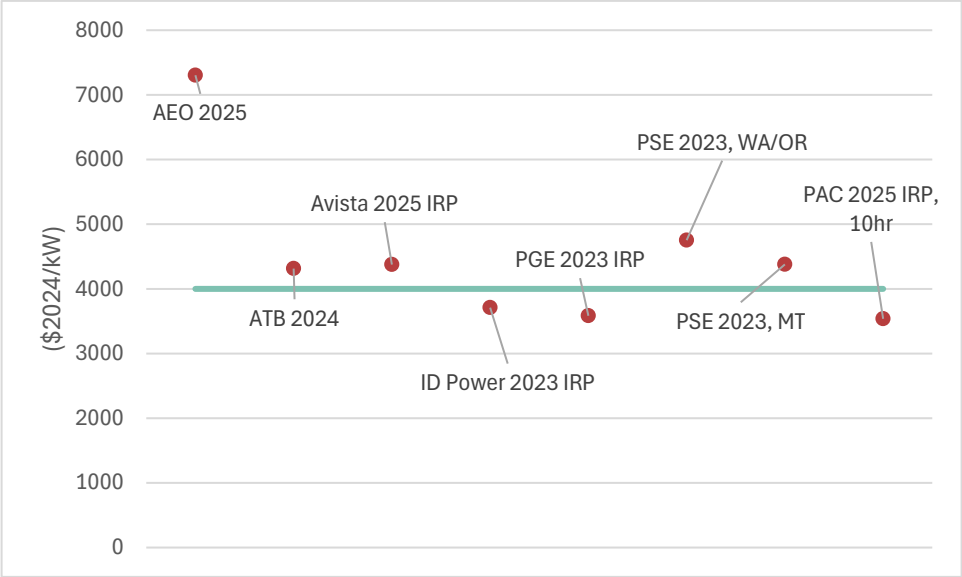
Plant name	State	Planned Capacity (MW)
Badger Mt	WA	500
Banks Lake	WA	500
Goldendale	WA	1200
Gordon Butte	MT	400
Cat Creek	ID	720
Dry Canyon	ID	1800
Elephant Rock (Neptune1)	OR	318
Owyhee	OR	600
Soldier Camp	OR	550
Swan Lake	OR	390
Winter Ridge	OR	500

[81] S&P Global.
[82] Ibid.

Cost

The literature review of pumped storage overnight capital costs, seen plotted in Figure G - 61, coalesces around $4000 /kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 61: Literature Review of Pumped Storage Overnight Capital Costs



There is not a cost curve for pumped storage. Per NLR's designation, pumped storage is considered a fully mature technology with no observable recent changes in cost or innovation.[83]

Summary Table

Pumped storage resource characteristics are collated in a table summarizing all that has been discussed in the preceding section. The summary of the reference plant is captured in Table G - 34.

[83] https://atb.nrel.gov/electricity/2024/pumped_storage_hydropower.

Table G - 34: Pumped Storage Reference Plant Summary Table

Reference Plant	Pumped Storage - 8 hour
Configuration	Closed loop, variable speed pump
Configuration	400 MW/8hr
Year Available to Model	2029 (5 yr lead time)
Development/Construction Period (Years)	2
Capacity (MW)	400[84]
Round trip Efficiency	80%
Overnight Capital Cost ($/kW)	4000
Fixed O&M Cost ($/kW-yr)	15
Variable O&M ($/MWh)	0
Economic Life (years)	50
Max Buildout	10 Plants (4000MW)

Emerging Resources

The Power Act requires that the Council give priority to cost-effective resources,[85] which in part requires the technology to be forecast as "reliable and available within the time it is needed."[86] The previously described resource categories, Primary and Limited Availability, fall within that definition and are treated accordingly. The Emerging Technology category is considered not yet "available and reliable." Despite not being "reliable and available" today, the Council analyzes these emerging resources to inform potential long-term strategies for resource development.

Proxy Reference Plant Approach

The emerging technology resources receive qualitative discussion of the status of their regional potential and are represented as proxies for future technology in analysis. The Council's approach to emerging technology has evolved across power plans, sometimes naming a specific resource or building a single proxy to represent all possible resources. For the Ninth Plan, the Council has opted for an expansion of the proxy approach, developing three emerging technology proxies in the hopes of revealing more about the system's needs. These three proxies are based on specific technologies that

[84] Approximate, pumped storage capacity is based off of previously cited projects, as explained above.
[85] Northwest Power Act, §4(e)(1).
[86] Northwest Power Act, §3(4).

embody sets of characteristics, but they may not be the only technologies that might fill the gap their selection identifies.

The intention behind building proxy resources is to avoid affording too much certainty around future technologies that are not yet proven on the scale necessary to the region. By building proxies that are representative of a set of characteristics, rather than a particular technology, the hope is to provide space to test within those characteristics. Even if those characteristics do not come to bear, these proxies still reveal something about regional system needs. The proxies are also available far enough out in the planning period that there will be time to revisit any assumptions by the next power plan if it becomes clear that adjustments are needed.

The Council has developed three proxy plants that represent a set of resource attributes and will provide insight into which of those potential attributes might provide the most value for the power system in the long-term. Those proxies, their representative technologies, and the information they provide are listed below. They will be described in more detail later in the section.

- **Clean Long Duration Storage**: Helps the grid better integrate variable resources, provides operational flexibility, and offers demand shifting on a seasonal scale. Represented by an iron-air battery.
- **Clean Baseload**: Offers reliability and firm supply to the grid. Represented by a small modular nuclear reactor.
- **Clean Peaker and Medium Duration Storage**: Mitigates high peak demand, while extending operational flexibility and shorter term, daily/hourly demand shifting. Represented by a hydrogen peaker plant with on-site production and storage.

Shared Emerging Technology Assumptions

Similar to the other resource types, emerging technologies share some assumptions across resources. These cross-cutting pieces are especially relevant to these proxy resources as they provide a level of parity and allow for more straightforward comparisons between resources. The nature of the proxies being so uncertain led to the conclusion that some equivalencies would be useful in the absence of certainty.

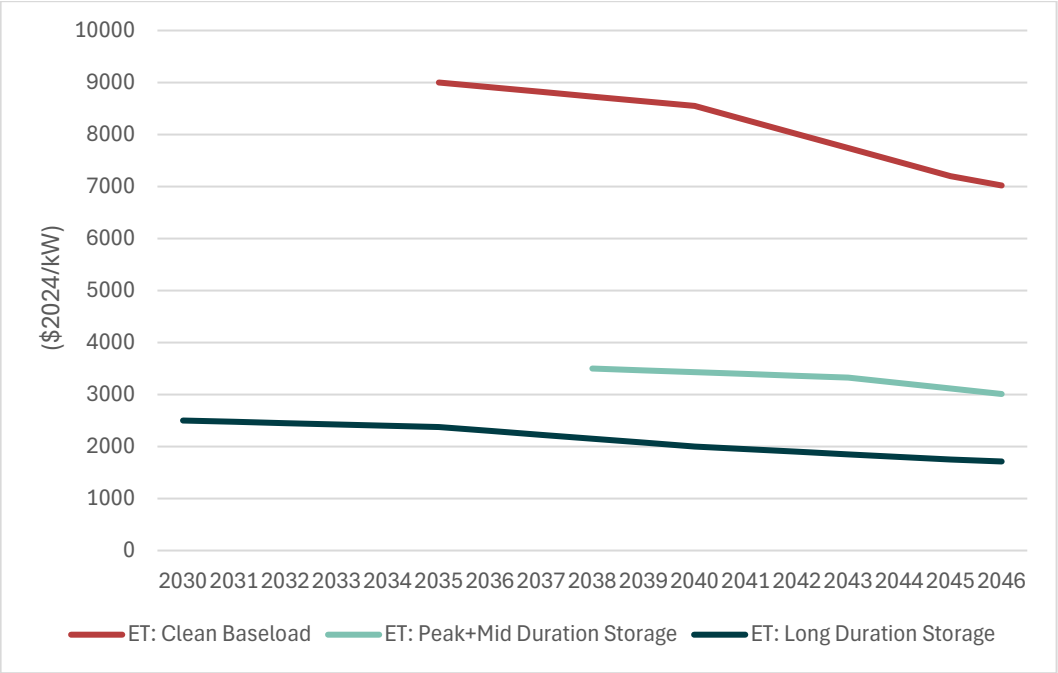
Cost Curves

For consistency, the cost curve for all emerging tech is based on the SMR curve developed in the NLR ATB[87]. SMRs, as the emerging technology that has been around the longest, has the most data and research around its potential costs. As in past plans, the Council has used the cost curves developed by NLR across emerging technologies under the assumption that these currently non-commercial

[87] https://atb.nrel.gov/electricity/2024.

technologies' costs might de-escalate in a similar manner as they mature and are more widely adopted. Figure G - 62 shows the final forward cost curves assumed for these technologies.

Figure G - 62: Forward Cost Curves of Emerging Technologies



Availability

Given the uncertainty around emerging technology characteristics, there was an effort to align, as appropriate, online dates, development period, and maximum buildouts so that technologies might be better compared to each other based on the above-described characteristics rather than the simple fact that they were more available or available earlier.

As was described for each primary and limited availability resource, the available online date of a resource refers to when the resource is available for the model to select and the development period denotes how long a resource takes, after being selected, to come online and be operational. For emerging technologies, the aspects of timing are fairly uncertain and fall outside of the first six years of the Ninth Plan horizon (also known as the action plan period). The iron-air batteries of the long duration storage proxy are currently operational, if not yet quite commercial, but the other two proxies are not. The assumptions outlined below are informed estimates, but an effort was made to align their timing so as to not favor one over the other.

A resource's maximum buildout sets the maximum amount of reference plant units that the model can select over the whole 20-year planning horizon. This is not stipulated for most primary resources, but it is assumed that emerging technology will be more limited in the early stages of their commercial availability. There was an attempt to align the amount of each resource available for the model to select in an endeavor to treat the proxies equivalently. These final availability decisions are shown in Table G - 35.

Table G - 35: Emerging Technology Availability[88]

Technology	Available online date	Max. Build
ET-Baseload (SMR)	2040	3000 MW (~5 units)
ET-Peaker + Med Duration Storage (H2)	2040	3000 MW (~10 units)
ET-Long Duration Storage (Iron air battery)	2032	1000 MW (by 2040) 2000 MW (by end of study)

Clean Baseload

Characteristics

One potential future need of the energy system is a clean baseload resource. It is often discussed that the modern grid, defined by high adoption of variable resources, aging and retiring coal plants, and a push for cleaner generation, lacks a firm supply. This resource can act as an underlying constant upon which the rest of the system is built, is big enough to fill any gaps, is consistently reliable, and is always on. The clean baseload proxy plant allows us to test if and under which conditions that need arises.

There are a number of resources currently under development, though not yet commercially available, that could fulfill these characteristics and meet potential future baseload need of the system. The intention of the proxy approach is, again, to not be overly prescriptive of the specific technology but to focus on the characteristics of the resource and what they mean for the region. A representative technology was selected as the basis for the proxy, due to relative technology maturity and regional interest, but there are other technologies that could address the same need. A few of those technologies are described at the end of the section.

Proxy Specifics: Small Modular Reactor

Small modular nuclear reactors (SMRs) were selected as the proxy resource in the 2021 Power Plan due to general enthusiasm and interest for the technology in the region and more broadly at the time. SMRs have stayed top of mind since the 2021 Power Plan with many regional IRPs including them in their models. Additionally, various tech companies have announced partnerships and plans to serve their data center loads with SMRs. The largest in-region announcement is Amazon's partnership with Energy Northwest and X-energy to build 320 MWs near the Columbia Generating Station, which represents a fraction of their planned 5 GWs of SMR development. Similar partnerships between tech companies and SMR developers are happening across the country with Oracle announcing 1 GW of

[88] The limits described in this table reflect what the GRAC thought were reasonable for availability limitations. The actual modeling did not implement these limits. Staff does not believe this changes results in the near-term. Further discussion of this disconnect can be found in Technical Appendix N—Scenario Modeling and Results.

SMRs, Google and Kairos Power planning 500MW, and Oklo and Switch penning a deal for 12 GW of SMRs by 2044. This high level of investment in SMR development made SMRs a logical choice to base this proxy on.

The emerging SMR technology's smaller size and modular construction is intended to reduce capital cost and investment risk, as compared to a conventional full-sized nuclear unit. It aims to do this by using a greater degree of factory assembly, shortening construction lead time, and better matching plant size to customer needs and finances through scaling of multiple units. The smaller plant size of SMRs may also permit greater siting flexibility, load following capability, and cogeneration potential. They can also benefit system reliability through reduction in "single shaft" outage risk with multiple independent reactor-generator pairings. One of the major challenges with any nuclear power plant is responsibly and safely storing and disposing of used fuel. While SMRs use less fuel, the technology does not resolve this concern entirely. More on the environmental effects of nuclear power and historical and current development can be found in Technical Appendix B – Existing System Parameters and Policies.

Availability

Many aspects of the SMR's availability have already been discussed above in the shared assumptions section. However, the technology has additional considerations to be made around capacity and efficiency. As with the other thermal resources, SMRs are modeled with a discrete size based on a literature review of available sources and conference with Council advisory committees. The same approach was taken to determining the heat rate, or thermal efficiency, of the resource. Those sources are shown in Table G - 36 below.

Table G - 36: SMR Operating Characteristics Literature Review

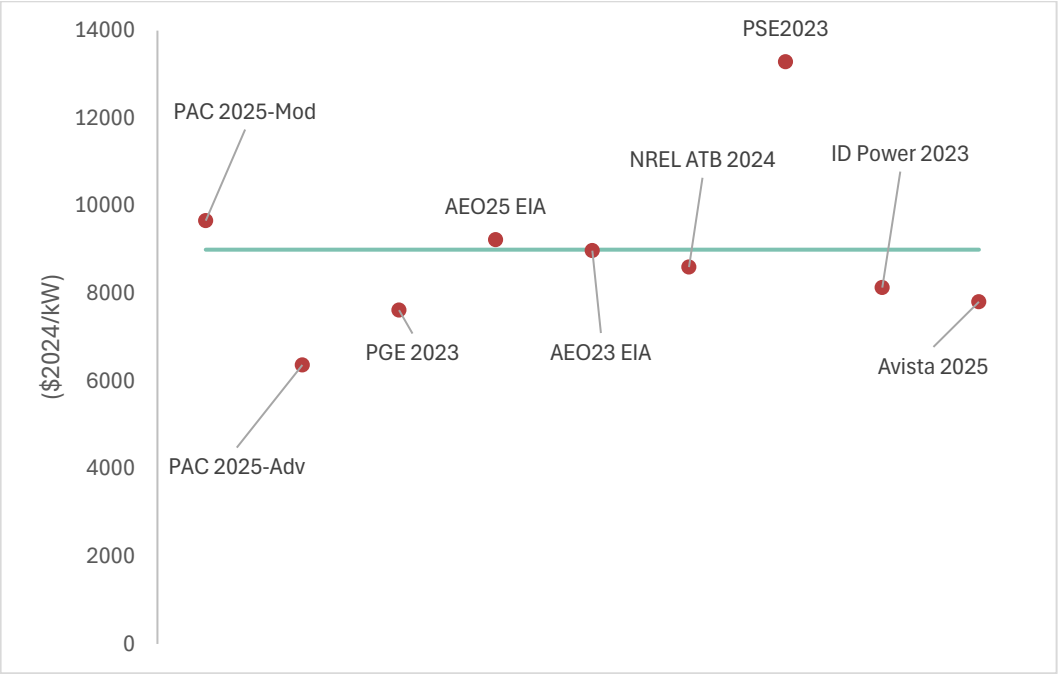
Source	Capacity	Heat Rate (HHV Btu/KWh)
PAC IRP-Moderate Tech Case	600MW	9180
PAC IRP-Advanced Tech Case	600MW	9180
PGE IRP	600MW	10046
AEO24 EIA	480MW	10046
AEO23 EIA	600MW	10447
NLR ATB	300 MW	9180
PSE IRP	600 MW	
ID Power IRP	100 MW	10461
Avista IRP	100MW	10443
Final Reference Plant	600MW	9800

Costs

Of the emerging technologies, SMRs have the most resources to draw on when exploring their potential costs and other operating characteristics. SMRs have been an emerging technology for longer than some of the other resources, and so there has been more time spent building up these technical resources.

The literature review of SMR overnight capital costs, seen plotted Figure G - 63, coalesces around $9000/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 63: Literature Review of Small Modular Nuclear Reactor Overnight Capital Costs



Fixed O&M costs as well as Variable O&M costs seen in Figure G - 64 and Figure G - 65 similarly cluster around a median cost, represented by the light blue lines. Fixed O&M around $120/kW-yr and Variable O&M at $4.50/MWh.

Figure G - 64: Literature Review of Small Modular Nuclear Reactor Fixed O&M Costs

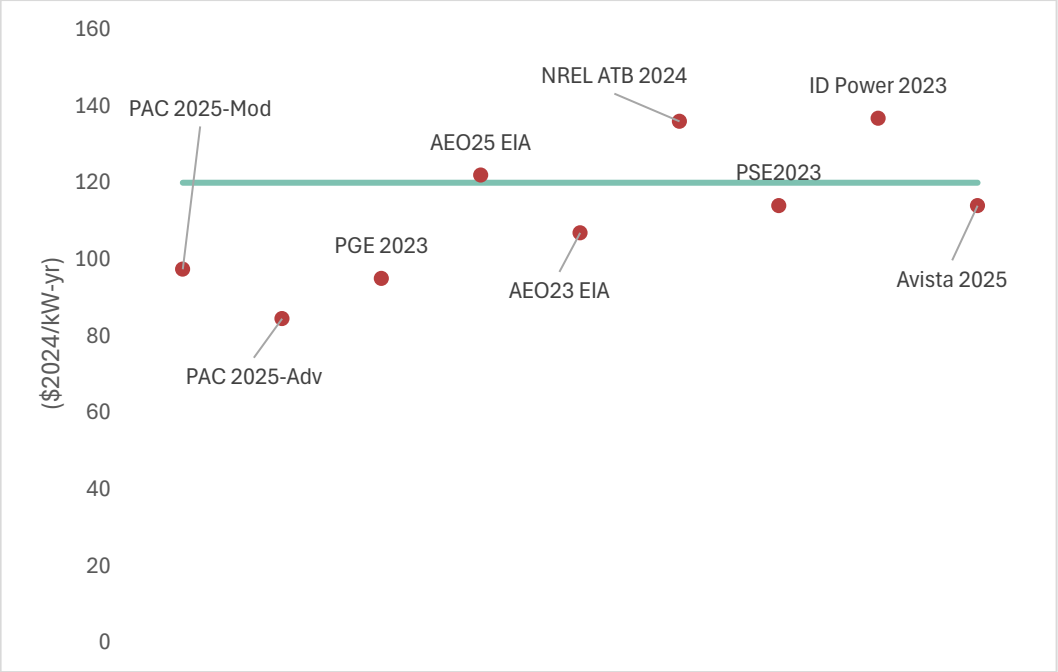
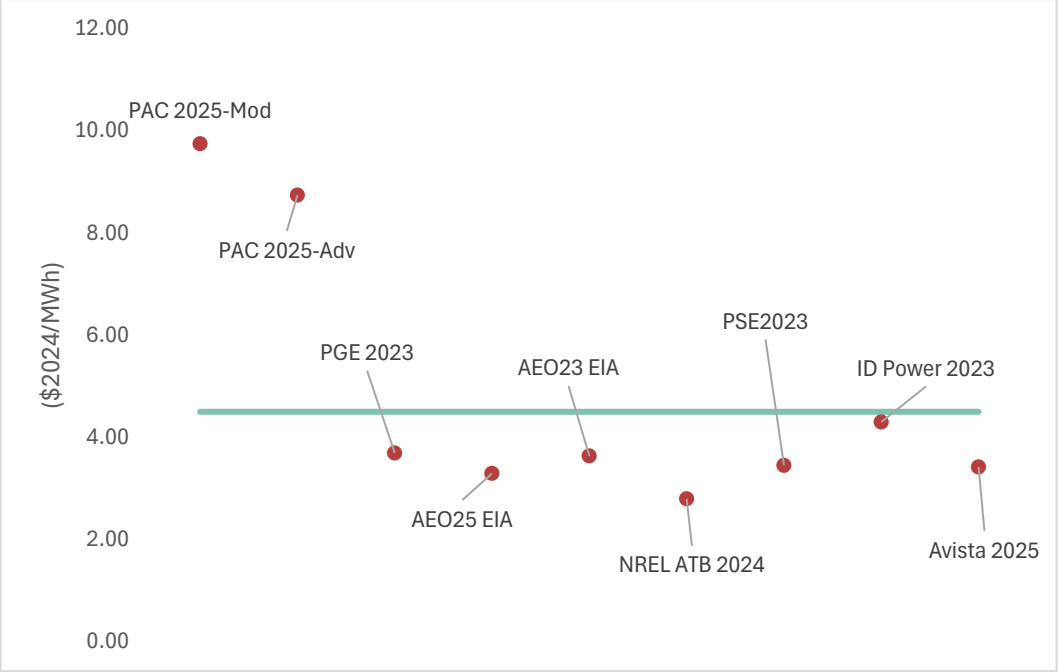


Figure G - 65: Literature Review of Small Modular Nuclear Reactor Variable O&M Costs



Alternative Technologies

Small Modular Reactors are not the only emerging technology that could fulfill the characteristics described by the clean baseload proxy. Other technologies covered by this proxy plant are described below.

Enhanced Geothermal

While conventional geothermal requires the natural occurrence of heat, water, and permeability, enhanced geothermal systems (EGS) only require the presence of hot rock. The permeability of the rock and the fluid are engineered through sub-surface fracturing and injection wells. Because hot rock exists everywhere beneath the Earth's surface (at varying depths), the geographic potential for EGS as a resource is greater than conventional geothermal. In addition to EGS, there is a further emerging technology known as "super hot rock" EGS, which taps into rock 400° Celsius and greater and at depths 5 kilometers and greater (often closer to 20 kilometers) – significantly amplifying the energy potential of the resource. However, to tap into super hot rock EGS, technological advances must occur in drilling equipment and techniques to safely reach the depths required.

Wave Energy

Beyond traditional hydroelectric power, there are other energy resources that can be derived from the naturally occurring phenomenon in the Earth's oceans and rivers and harnessed into electricity, including currents, tides, and waves. While all are considered emerging, wave energy appears to be an appealing match for the Pacific Northwest power system because of the high energy potential along the Pacific coastline from California to Alaska. Wave power devices and converters capture energy through motion at the surface or through the pressure fluctuations from the waves below the surface. While highly seasonal and subject to storm-driven peaks, wave energy is relatively continuous and predictable. In the region there is a grid-connected, pre-permitted, open ocean wave energy test facility, which is the only one of its kind in the nation.[89] This project, operated by PacWave and Oregon State University, is a meaningful step in testing the viability of wave energy in the US and moving the technology towards commercial.

Summary Table

The summary of the reference plant is captured in Table G - 37.

[89] https://pacwaveenergy.org.

Table G - 37: Clean Baseload Proxy Resource Reference Plant Summary Table

Reference Plant	Clean Baseload Proxy
Configuration	Small Modular Reactor
Year Available to Model	2035
Development/Construction Period (Years)	5
Capacity (MW)	600
Heat Rate	9800 Btu/kWh
Overnight Capital Cost ($/kW)	9000
Fixed O&M Cost ($/kW-yr)	120
Variable O&M ($/MWh)	4.50
Economic Life (years)	30
Max Buildout	3000 MW

Clean Long Duration Storage

Characteristics

A more dynamic and variable grid requires more flexibility to operate effectively. An energy system more reliant on renewables, and therefore a variable fuel source, can still be a balanced and reliable one thanks to its capabilities to store excess energy that is produced when there's less demand, and shift it to be used when it's needed. Recent storage adoption trends reinforce this. The most common and available storage resource currently is the lithium-ion battery, which is discussed above. This shorter duration storage can store 4-8 hours of electricity, which means that shifting is only happening within a day. Storage that has a longer duration (the ability to shift between days or seasons) might be beneficial to the system by providing further variable resource integration and operational flexibility. The intention of the clean long duration storage proxy is to test that assertion, as well as to test which resources it pairs well with and how the system might use that flexibility.

There is more than one long duration storage resource that exhibits these characteristics and could provide flexibility to the future system. A single representative technology was selected as the basis for the proxy, due to relative technology maturity and regional interest, but there are other ways to address the same need that have the potential for storing energy for longer durations. Those broad storage mechanisms and some of the ways they are employed are described at the end of the section.

Proxy Specifics: Iron Air Battery

With factories in production and successfully completed test projects, the long duration energy storage technology closest to commercial readiness is the iron air battery.

Iron air batteries employ reverse rusting. On discharge the battery uses oxygen from the air to convert iron metal into rust. When charging an electrical current, the battery converts the rust back to iron and releases oxygen. The battery features a thin sheet cathode on one side, an anode made of powdered iron held together with mesh on the other, and a water-based electrolyte in the middle. Air passes through the cathode and reacts with the electrolyte creating negatively charged hydroxide ions on the inside surface of the cathode. That surface crowds with ions and they then move toward the iron, latching on and creating iron hydroxide, or rust. That causes the ions give up electrons, which are guided out of the battery in the form of an electrical current. After 100 hours, that iron is totally rusted through, and the battery runs out.

To recharge the battery – to "unrust" it – a current is sent back through the system, reversing the chemical reactions. Introducing electrical current into the system breaks the rust back down into its oxygen and iron components. The oxygen leaves the cell as bubbles; the iron is left whole and metallic again.[90]

This cycle is durable and repeatable, though not particularly efficient – the round-trip efficiency is about 40%. The batteries operate modularly, with each power block only requiring a third- to a half-acre per megawatt. This relatively small footprint and modularity make these batteries easy to site near where they're most needed. Compare the footprint to the approximately five acres per megawatt needed for a solar farm, as well as the 24-125 acres per megawatt for a wind facility.[91]

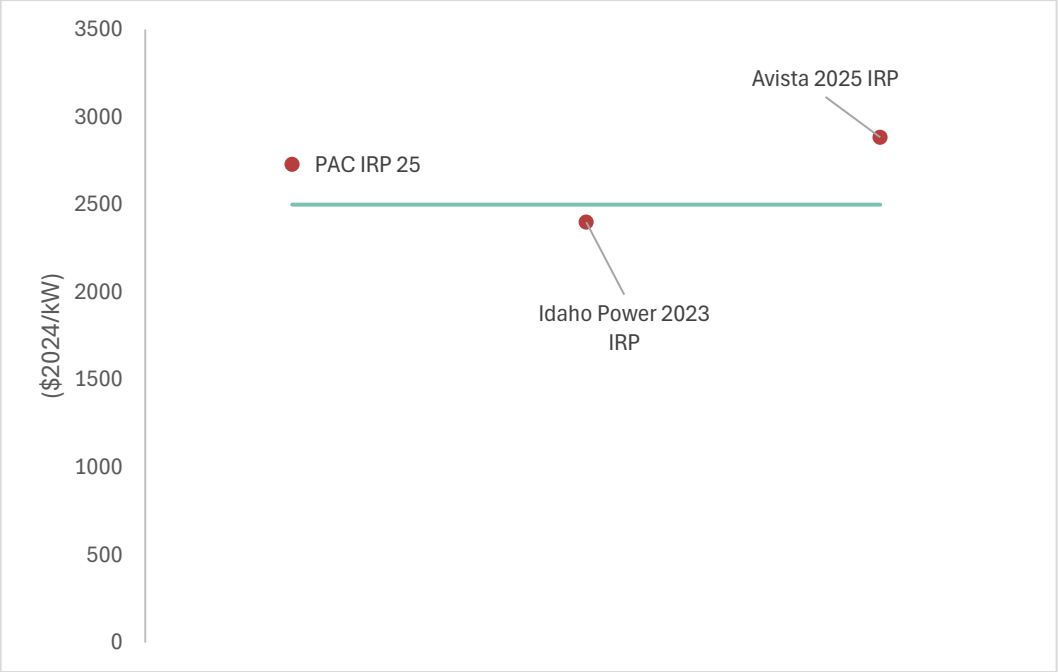
This proxy plant is specifically based on Form Energy's Iron Air Battery, because they are currently the only producer of the technology.[92] Early in Ninth Plan's time period, the technology's availability is based on Form's current production capabilities. However, later in the power plan period, the maximum buildout allowed by the models is expanded to capture future development in this space – either by Form or by other technologies that fill the same niche.

Costs

Iron air batteries show up in regional IRPs and there has been significant interest for the technology in the region. However, it is not yet in the larger national reports and studies that fill out many other technologies' literature reviews. Figure G - 66 below shows what data were collected.

[90] https://www.pbs.org/wgbh/nova/article/iron-air-battery-renewable-grid.
[91] https://www.energy.gov/sites/prod/files/2019/05/f63/gagne-rule-thumb-ppt.pdf.
[92] https://formenergy.com/technology/battery-technology.

Figure G - 66: Literature Review of Iron Air Battery Overnight Capital Costs



The literature review of iron air battery overnight capital costs coalesces around $2500/kW, shown by the light blue line. This final cost is also informed by conversations with Form Energy about the specifics of their technology and their recommendation for modeling its operations. The information they shared with Council staff is shown in Table G - 38 and was intended to support modeling of the iron air technology in planning applications such as IRPs or, in the case of the Council, a regional power plan. These numbers were then gut-checked by the Council's Generating Resource Advisory Committee, so as to not take marketing numbers at face value.

Table G - 38: Iron-Air Cost and Performance from Form Energy Performance Specs[93]

Discharge duration at full rated capacity	100 hours
SKU1 (1x charge power), All-in installed capital cost ($/kWh)*	$15 – $20
SKU2 (2x charge power), All-in installed capital cost ($/kWh)*	$18 – $23
Fixed O&M ($/kW-year, Yr 1 dollars)	$15 – $20
Round trip efficiency**	40 – 45%
Charge efficiency	69 – 73%
Discharge efficiency	58 – 62%

[93] https://formenergy.com/wp-content/uploads/2025/01/Navigating-the-Pacific-Northwests-Energy-Challenges.pdf.

Annual discharge throughput limit	1,500 – 2,000 equivalent hours at full power
Enclosure lifetime	15 – 20 years
Power degradation	0% / year
Energy capacity degradation	2% / year
Energy efficiency degradation	0.5% / year

* Landed costs of the AC modular power block at ~100mw scale, inclusive of EPC, developer costs, and grid interconnection costs.
** AC-AC round trip efficiency, full charge and full discharge at rated power, inclusive of losses from power conversion and auxiliary loads.

Alternative Technologies

Other technologies can store energy for longer durations than the standard 4-hours of lithium-ion batteries. A few additional forms of storage are described below.

Electrochemical Energy Storage

Electrochemical energy storage stores energy of chemical reactions, where electrical energy is converted to chemical energy and vice versa. Metal anode batteries are the most straightforward example of the storage type, with lithium-ion batteries being one of the most common commercial storage types. However other metal types can be applied as in lead-acid and sodium sulfur batteries. Flow batteries are another type of electrochemical storage, working by pumping negative and positive electrolytes through energized electrodes in electrochemical reactors (stacks), allowing energy to be stored and released as needed. Vanadium redox flow batteries are currently the most technologically mature flow battery type, with a number of pilots and small-scale plants installed and operating across the world.[94]

Iron air batteries are another means of harnessing electrochemical storage. The iron air battery forms the basis of our proxy reference plant.

Mechanical Energy Storage

Mechanical energy storage stores kinetic or potential energy by compression, gravity, or rotation, prototypically exemplified by pumped hydro storage. Other versions of mechanical storage are gravity-based, which raises concrete blocks to store energy and lowers them to generate electricity, and compressed air energy storage (CAES)/liquid air energy storage (LAES), which use compression and expansion to store excess energy. Many of these forms of mechanical energy storage are being pursued in the industry. Hydrostor has developed a CAES technology with projects globally, as well as

[94] https://batterycouncil.org/battery-facts-and-applications/about-flow-batteries.

in California, under development.[95] While Energy Vault has gravity energy storage systems already operating, more are scheduled in the coming years.[96]

Thermal Energy Storage

Thermal energy storage stores energy as heat. One version of such storage technology is sensible heat (molten salts), which heat low-cost materials (such as salt) to high temperatures to generate steam. Another version is latent heat, which uses phase change technology to liquefy air at low temperatures and then convert it back into gas to drive electricity production. The most common version of this storage type is concentrated solar power that stores solar energy thermally and then dispatches it as a battery.[97] This technology has existed for some time, but has not reached the commercial penetration of traditional solar PV.

Summary Table

The summary of the reference plant is captured in Table G - 39.

[95] https://hydrostor.ca/projects.
[96] https://www.energyvault.com/products/g-vault-gravity-energy-storage.
[97] https://www.solarpaces.org/how-csp-thermal-energy-storage-works.

Table G - 39: Clean Long Duration Storage Proxy Resource Reference Plant Summary Table

Reference Plant	Clean Long Duration Storage Proxy
Configuration	Iron Air Battery-100hr
Year Available to Model	2030
Development/Construction Period (Years)	2
Round trip Efficiency	40%
Overnight Capital Cost ($/kW)	2500
Fixed O&M Cost ($/kW-yr)	20
Variable O&M ($/MWh)	0
Economic Life (years)	30
Max Buildout	1000 MW (2040) +2000 MW (by 2046) 3000 MW total

Clean Peaker with Medium Duration Storage

Characteristics

Another potential problem that might arise on the existing grid is high peak loads that must be met quickly, yet only briefly. In the current system those spikes in demand are often met by natural gas peaker plants, which are on-demand and can be turned on and off quickly. However, as policies push towards decarbonization, a clean alternative might be necessary to fill that gap. This need can be served by a storage resource that operates on a daily or hourly scale, or by a similar combustion technology utilizing a cleaner fuel. The proposed clean peaker/mid-duration storage proxy plant would serve as that resource. Including it in this plan will test the grid's need for such a technology, as well as the type of resource mix selected around it. However, as with the other emerging technology proxies, there are other technologies that could do the same job. A few of these technologies are described below.

Proxy Specifics: Hydrogen Combustion Turbine with Onsite Electrolysis

The technology selected to serve as the basis for the proxy is an all-hydrogen burning combustion turbine with onsite hydrogen production and storage via clean electrolysis. Hydrogen was selected as the representative technology because there is a lot of interest in hydrogen in the region and nationally. Many utility IRPs also consider hydrogen. These plants operate similar to the traditional combustion technologies of coal and natural gas, but rely on a non-emitting fuel. This makes it potentially a nice fit for the existing system to meet clean policies. However, there is no existing infrastructure for hydrogen, and most forecasts do not show significant hydrogen for power use until

the 2040s.[98] Non-power applications are forecast sooner,[99] and discussion of that and its implications for the grid can be found in Technical Appendix F – Electricity Demand Forecast.

The proxy hydrogen resource selected as the basis for the reference plant does not rely on new pipeline infrastructure or a whole hydrogen economy. Rather, it behaves like a peaker plant with onsite production and storage. The process of splitting water into hydrogen and oxygen gases requires a significant amount of electricity, which the Council models similar to other storage resources with a load impact. This results in a resource that essentially operates as a medium duration storage plant. The hydrogen would be produced by electrolysis via polymer electrolyte membrane (PEM) electrolyzer and stored onsite in 24-hour tanks, ready to be used when needed.

Availability

Many of the operating characteristics of the hydrogen proxy are based on the simple cycle frame turbine because that technology combusts the hydrogen fuel and produces electricity. This means that the discrete size of the proxy plant is set at 250 MW in a mirror of the SSCT frame reference plant. Similarly, the heat rate, or the thermal efficiency of combusting the hydrogen for electricity, is the same as the frame plant, 9800 Btu/kWh.

The medium duration aspect of the proxy resource is from the PEM electrolyzer, which produces the hydrogen vie electricity. As a storage resource it has a system efficiency measured through the discharge/recharge cycle. The ratio of useful energy output to useful energy input, or the round-trip efficiency, is relatively low, meaning the process is fairly inefficient with an RTE of 40%.[100,101]

Costs

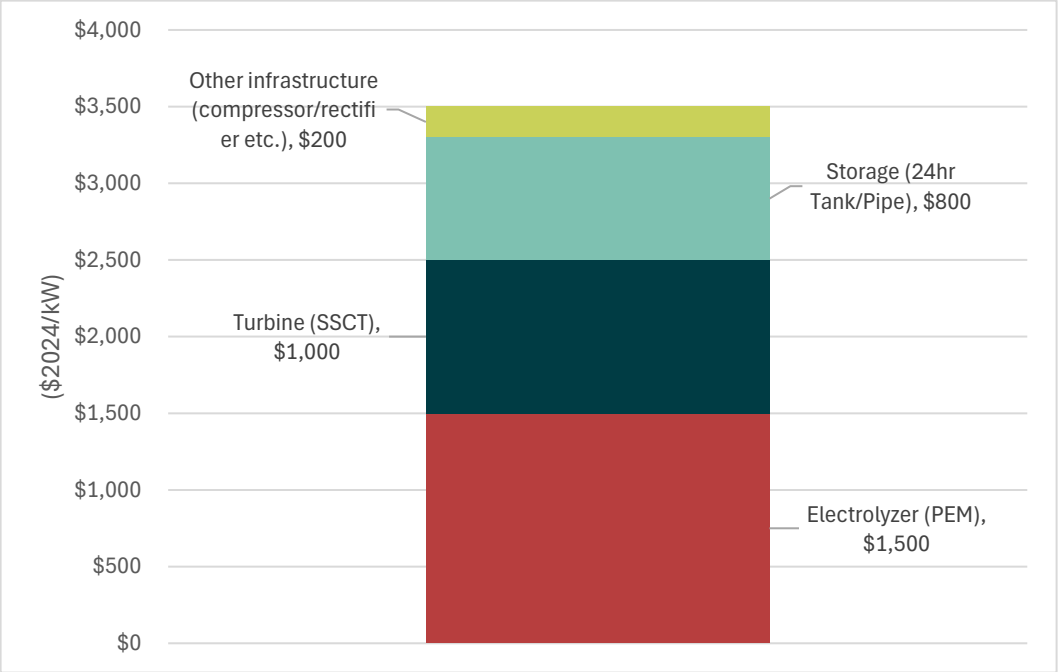
This hydrogen proxy plant total cost was built up by combining the component parts necessary to operate the plant as described. Those parts are described below and their costs are shown in Figure G - 67.

- PEM electrolyzer: Produces the hydrogen on site and is the main cost component.
- Storage system: Stores the produced hydrogen for future use in a 24-hour tank/pipe. Geologic storage was considered, but was determined to be too geographically constraining.

[98] https://h2fcp.org/system/files/cafcp_members/2024%20DOE%20Pathways%20to%20Commercial%20Liftoff%20-%20Clean%20Hydrogen.pdf.
[99] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf?sfvrsn=c425b44f_5.
[100] https://www.sandia.gov/app/uploads/sites/163/2022/03/ESHB_Ch11_Hydrogen_Headley.pdf.
[101] https://www.cell.com/joule/fulltext/S2542-4351(21)00306-8.

- Combustion turbine: Uses the hydrogen fuel to produce electricity. This technology is essentially the same as a new simple cycle turbine and its costs were based off the simple cycle turbine reference plant costs.
- Any additional infrastructure: Includes things such as the compressor and rectifier which are necessary for running the plant.

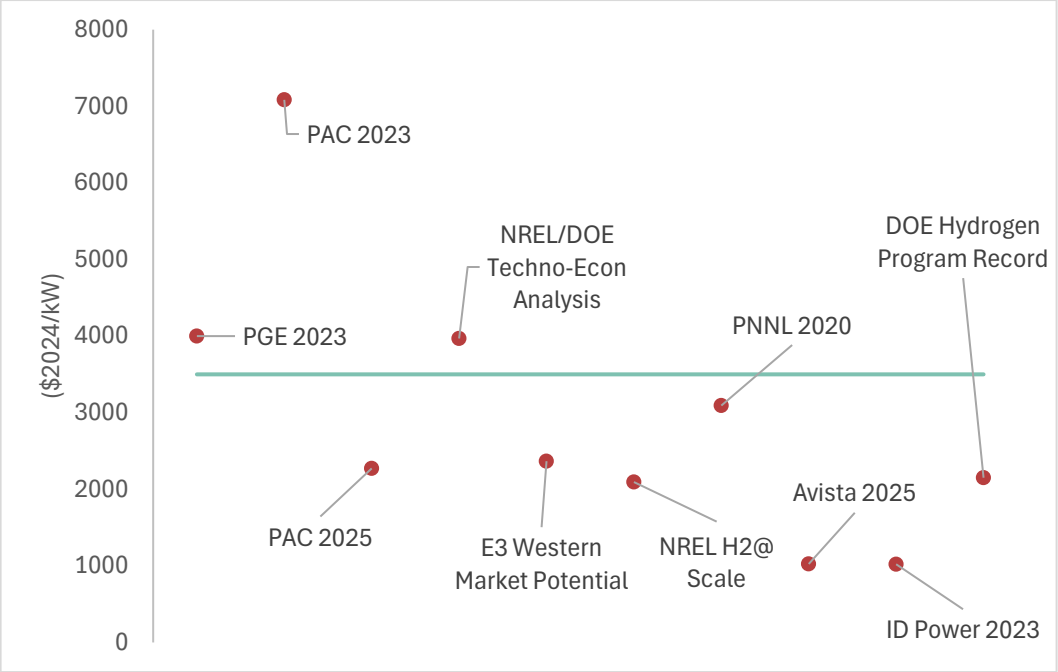
Figure G - 67: Hydrogen Proxy Plant Costs[102]



The data points in Figure G - 68 are not perfectly comparable costs, as the different sources refer to different configurations of different components. The most complete cost for our purposes is from the NLR/DOE Techno-Economic Analysis.[103] The literature review seen plotted in Figure G - 68, groups around $3500/kW, shown by the light blue line. Variable and fixed O&M for the hydrogen proxy resource are based off of the simple cycle combustion turbine operation costs for lack of alternative cost data for hydrogen specific plants.

[102] https://www.cell.com/joule/fulltext/S2542-4351(21)00306-8.
[103] Ibid.

Figure G - 68: Literature Review of Hydrogen Peaker Overnight Capital Costs



Alternative Technologies

Flywheel Energy Storage

Flywheels store energy by spinning a rotor in a low-friction enclosure, which changes speed when moving energy to or from the grid. They are mainly used in this peaking capacity for grid management, especially frequency control due to their rapid discharge. Flywheel storage power systems are currently operating at various scales across the world. The largest deployment of grid-scale flywheel storage is a 30 MW plant in China that was connected to the grid in 2024.[104] Beacon Power operates 2 20MW plants in Pennsylvania and New York State,[105] while Temporal Power operates smaller scale installations (2-5 MW) in Canada and Aruba.[106] While the technology has proven its reliability, it is not yet commercially available at scale.

Alternative Hydrogen Sources (Ammonia and Hydrogen via Pyrolysis)

Hydrogen can be used in a simple cycle turbine as a clean fuel alternative to natural gas. There is more than one way to produce hydrogen fuel. All modes of producing hydrogen take energy and can therefore be used as a form of storage.

[104] https://www.ess-news.com/2024/09/13/china-connects-its-first-large-scale-flywheel-storage-project-to-grid.
[105] https://beaconpower.com/operating-plants.
[106] https://ieso.ca/en/Powering-Tomorrow/2017/High-Performance-Flywheel-Energy-Storage-Systems-Temporal-Power.

Ammonia is the most efficient carrier for transporting and storing hydrogen as it takes up less space than hydrogen in its gaseous form. Applying high heat to ammonia (NH3) can 'crack' it into nitrogen (N2) and hydrogen (H2) once it is transported to its destination. Ammonia production is not necessarily clean, as it is typically derived from natural gas via steam methane reforming. Currently ammonia is primarily used in producing fertilizer, but there has been recent interest in its potential role in a future hydrogen economy.[107]

Hydrogen can also be produced via pyrolysis, which is a process that applies high heat to methane gas in an oxygen-free environment to produce hydrogen and a solid carbon byproduct. Northwest Natural began a three-year pilot project in 2024 that explores potential hydrogen applications with hydrogen produced via pyrolysis, particular blending hydrogen with natural gas to reduce the carbon intensity of its combustion.[108] The Council's Generating Resources Advisory Committee discussed this technology as a less electricity intensive process for producing hydrogen. Ultimately, the Council did not develop this into a reference plant due to insufficient data about large-scale project costs and availability, as well as the usage of natural gas.

Summary Table

The summary of the reference plant is captured in Table G - 40.

[107] https://kleinmanenergy.upenn.edu/research/publications/ammonias-role-in-a-net-zero-hydrogen-economy.
[108] https://s23.q4cdn.com/611156738/files/doc_news/NW-Natural-and-Modern-Hydrogen-Unveil-Clean-Hydrogen-Production-Carbon-Capture-Project-in-Portland-2024.pdf.

Table G - 40: Clean Peaker w. Medium Duration Storage Proxy Resource Reference Plant Summary Table

Reference Plant	Clean Peaker & Mid-Duration Storage Proxy
Configuration	Hydrogen peaker plant with onsite electrolysis
Year Available to Model	2038
Development/Construction Period (Years)	2
Capacity (MW)	250[109]
Roundtrip Efficiency & Heat Rate	40% 9800 Btu/kWh[110]
Overnight Capital Cost ($/kW)	3500
Fixed O&M Cost ($/kW-yr)	16
Variable O&M ($/MWh)	6.50
Economic Life (years)	30
Max Buildout	3000 MW

Levelized Cost of Energy

One way to compare the cost of a generating resource against another is to look at the levelized cost of energy (LCOE), which is a metric used to estimate the price of electric generation across a resource's expected economic life. It is calculated as the cost per unit of energy a resource is expected to generate (under an assumed level of dispatch, or capacity factor) and which also includes variable costs such as fuel. Although the initial capital cost for solar and wind may be higher than gas resources, with minimal operating costs (no fuel purchases), the overall cost of producing energy can be significantly less.

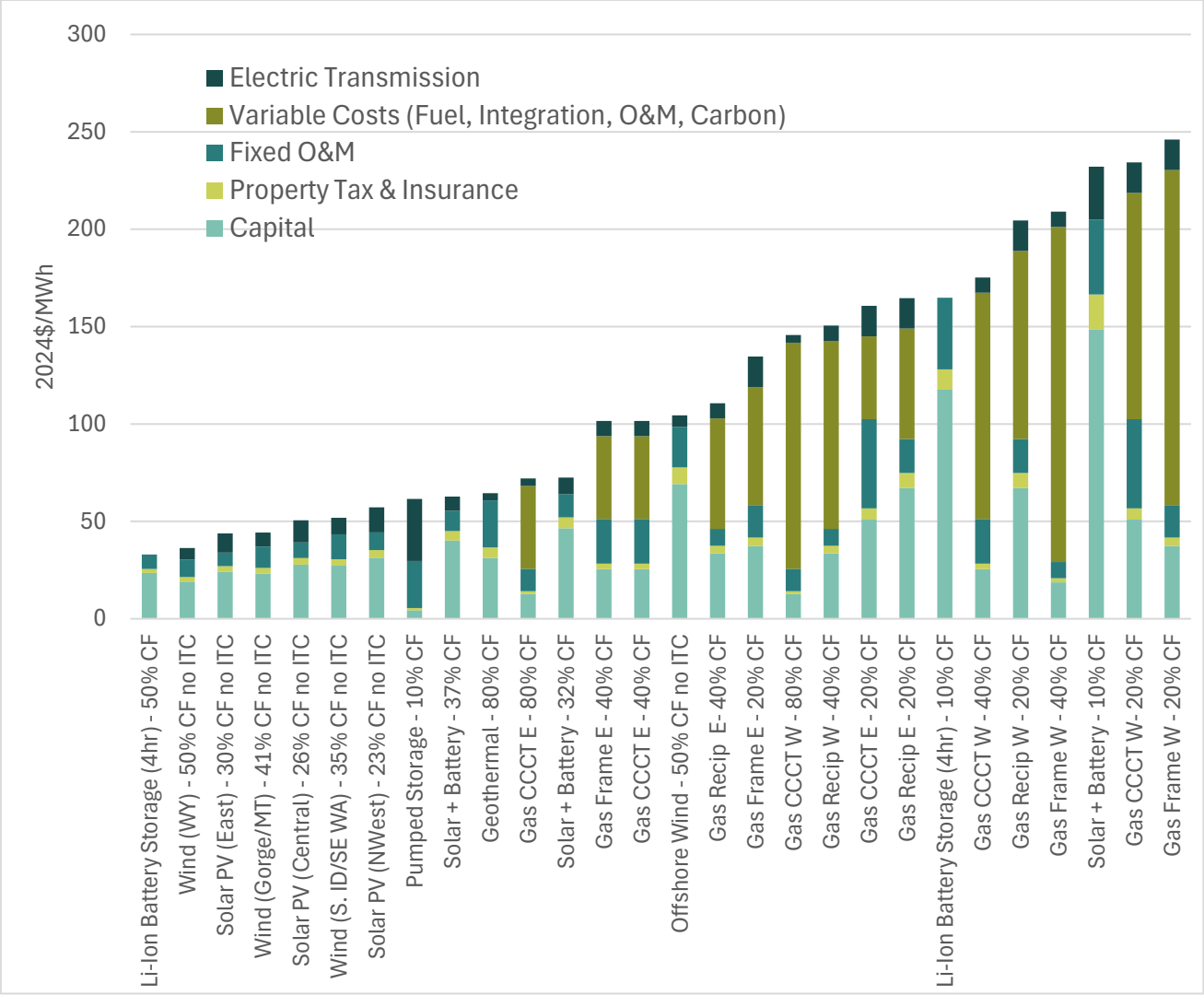
The Council does not use any of the static levelized cost of energy for generating resource reference plants for modeling (as shown in Figure G - 69) because the models are capable of performing dynamic dispatch. LCOE calculations rely on a static assumption of dispatch, which are not accurate in all hours of a dynamic system. Reflecting an assumed dispatch of 60%, for example, would indicate substantially better economics than would be realized if the actual dispatch was closer to 10% in some hours. LCOE calculations are highly dependent on the amalgam of underlying assumptions behind a resource and all of the costs and values accrued over its expected life. These assumptions often vary across studies or sources, making LCOEs complicated to compare.

[109] Based off of the size of a simple cycle combustion turbine.
[110] Based off of the size of a simple cycle combustion turbine.

MicroFin

MicroFin Is the Council's financial revenue requirements model used to calculate levelized fixed cost and LCOE that allow resources to be competed against each other. The levelized costs produced by MicroFin can be used as an illustrative metric for comparison between generating resource alternatives. Figure G - 69 shows the levelized costs of some of the Ninth Plan reference plants in order of least to most costly.

Figure G - 69: Reference Plants' Levelized Cost of Energy Estimates



As described in the section above, these costs on their own aren't particularly useful due to the flattening assumptions required to achieve a static representation of a dynamic system. However, it can reveal some useful trends when considering the resources in relationship to each other. For example, it is notable in Figure G - 69 that the bulk of the natural gas resource's costs are the olive

green bar for variable costs, namely fuel, which puts them closer to the end of the chart over the resources with no fuel costs. Another trend the figure illustrates is the importance of a resource's capacity factor. Higher capacity renewable resources, like wind in Wyoming or solar in the east portion of the Northwest where those resources are more abundant, drive the levelized costs down.

Uncertainty

These reference plants are intended to represent a typical given resource and are therefore generalizations by design. The work of power planning always takes place under uncertainty, and some of that uncertainty comes from the necessary imprecision of these defined resource choices. One way the Council is accounting for that uncertainty in the Ninth Plan is through scenario analysis. The Ninth Plan includes the Resource and Transmission Risk Scenario designed to test the impact and risk of changing resource availability, resource costs, and transmission availability. Different sensitivities will explore how changing resource characteristics might change the resource mix selected by the model. This analysis is intended to help the Council learn which resources and in what amounts can be robust across the range of uncertainty, and what resources or suite of resources should be built to mitigate different risks. Figure G - 70 describes the resource and transmission risk sensitivities and what questions they will be testing.[111]

Figure G - 70: Scenario Analysis Sensitivity Identified and Described

Constrained New Resources and Transmission Options	How would new resource additions change with limitations on what the region can build?
Changing Transmission Availability	How does the pace of transmission development impact new resource selection for the region?
Changing Emerging Technology Costs	How does the uncertainty around the cost of emerging technologies impact the new resource selection?
Limited Short-Duration Storage Availability	How would new resource additions change if the amount of new storage available was limited?
Slower Demand Side Resource Availability	How would new resource additions change if demand side resources took longer to develop?
Evolving Federal Policy Landscape	How do changes at the federal level impact resource decisions in the region?

[111] More information on the scenarios and sensitivities explored in the Ninth Power Plan can be found in Appendix N – Scenario Modeling and Results.

Constrained World Sensitivity

The Constrained World Sensitivity is designed to capture the risk associated with the ability to build new resources and transmission, as well as uncertainty around emerging resource opportunities.

For primary and limited availability supply-side resources, the Council assumed higher costs and limited the near-term availability (the first six years). This sensitivity also assumes a ten-year delay of emerging technology resources.

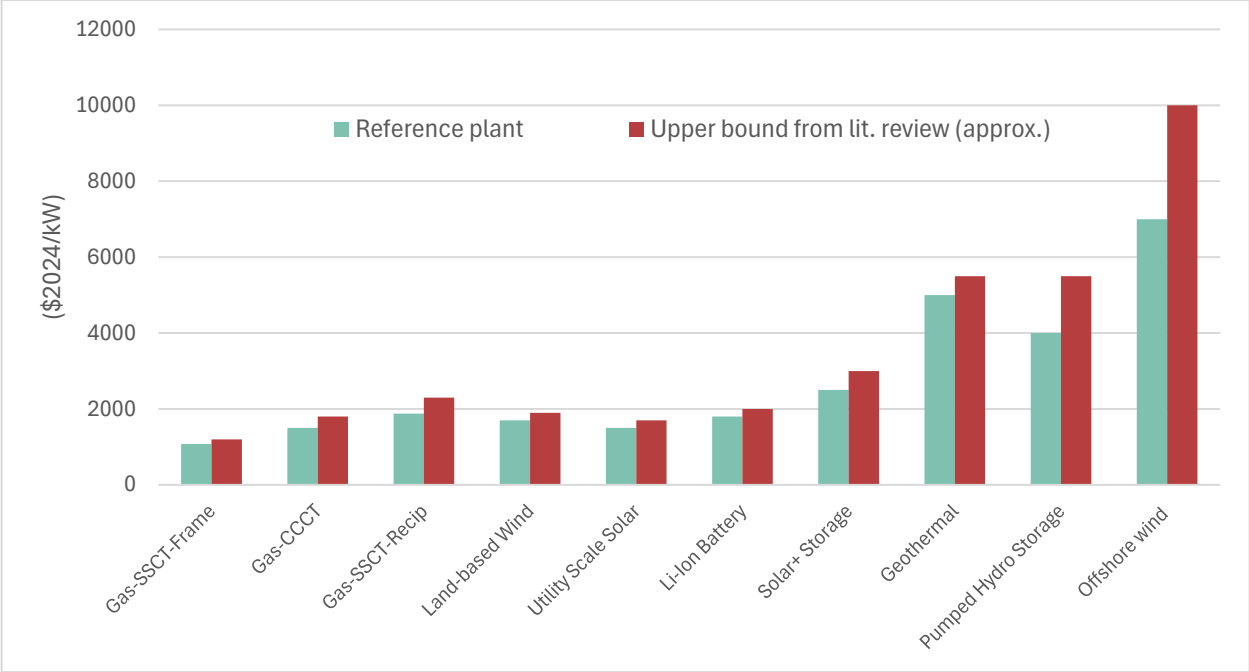
The higher resource costs are based on the upper bound price found in the literature review of each resource. Notably, the limited availability resources have a larger range, likely by virtue of being site-specific and more challenging to generalize. These high costs are captured in Table G - 41 and Figure G - 71.

Table G - 41: Upper Bound Capital Cost from Resource Literature Review

	Upper bound from lit. review [112](2024$)	Reference Plant Overnight Capital Cost (2024$)	Cost Change (2024$)	Percent Change in Cost
Gas-SSCT-Frame	1200	1078	122	11%
Gas-CCCT	1800	1500	300	20%
Gas-SSCT-Recip	2300	1878	422	22%
Land-based Wind	1900	1700	200	12%
Utility Scale Solar	1700	1500	200	13%
Li-Ion Battery	2000	1800	200	11%
Solar+ Storage	3000	2500	500	20%
Geothermal	5500	5000	500	10%
Pumped Hydro Storage	5500	4000	1500	38%
Offshore wind	10000	7000	3000	43%

[112] Details behind these higher cost levels can be found in this workbook: https://nwcouncil.box.com/v/9thPlanRefPlantCosts. They have been rounded to the nearest hundred for ease, and to avoid false precision.

Figure G - 71: Resource Cost Change in Constrained World Scenario



The build limit in this scenario is set to roughly half the limit assumed in for the reference build limit of other sensitivities. Table G - 42 shows the assumed annual build limit in megawatts for each year modeled in the scenario modeling.

Table G - 42: Annual Build Limit in Constrained World Sensitivity

Year	2028	2030	2032
Annual Build Limit (MW)	2,600	6,900	12,100

Limited Battery Storage Sensitivity

The Limited Battery Storage Sensitivity explores the impacts of near-term limitations on the availability of short-duration, lithium-ion, batteries. It limits the amount of battery acquisition that can occur in the action plan period, or the first six years of the study. The dampened availability will be set by a similar logic of the build limit in the constrained world scenario, based on the annual real world planned builds for upcoming years. The cumulative build maximum is shown by two-year increments in Table G - 43, with 3000MW of batteries allowed by 2028, 3500MW by 2030 and 4350MW by 2032 at the end of the action plan period.

Table G - 43: Annual Build Limit in Limited Battery Storage Sensitivity

Year	2028	2030	2032
Planned Batteries Only (MW)	3000	3500	4350

Variable Emerging Technology Costs Sensitivity

Recognizing the inherent uncertainty in emerging technology costs, this sensitivity explores the price points different emerging resources might make more sense for future needs.

This sensitivity will test both an increase in cost by 50% and a decrease in cost of 25%. This is based on the range of SMR costs in the literature review. This range is shown in Figure G - 72. The high end, shaded in blue, shows the 50% increase and the low end is captured by the 25% decrease, shaded in yellow. The cost variance is applied to the emerging technology overnight capital costs in Table G - 44.

Figure G - 72: Illustrative Cost Range of Emerging Technology Proxy

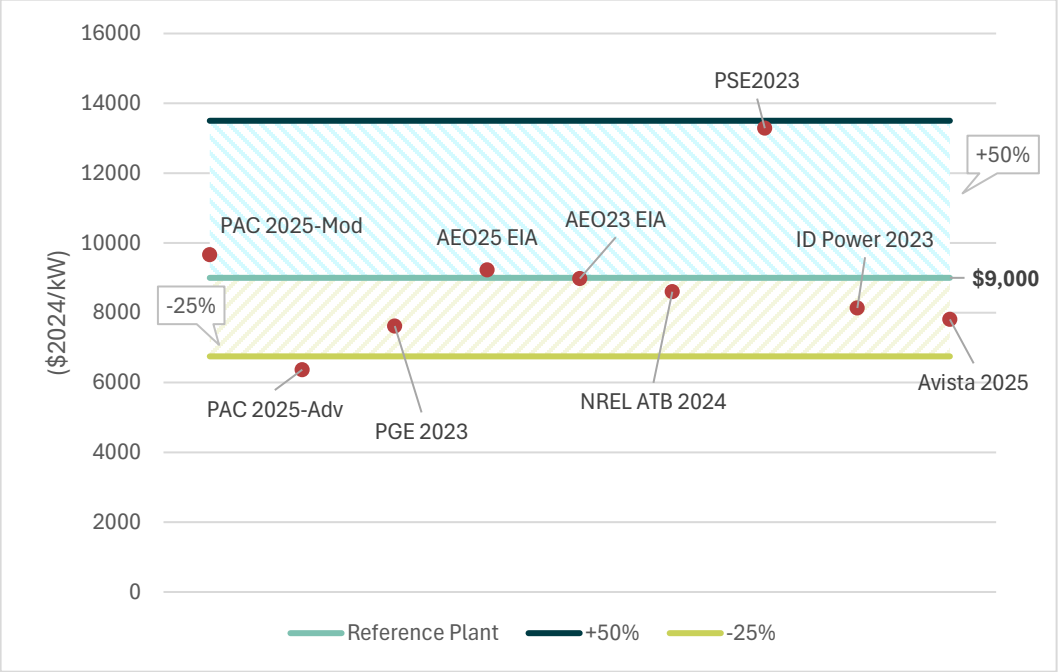


Table G - 44: Variable Capital Costs of Proxy Emerging Technologies for Scenario Analysis

ET Resource	25% Less	Proxy Plant OCC (2024$)	50% More
Clean Baseload (SMR)	$6750	$9000	$13500
Clean Mid-Duration Storage (H2)	$2625	$3500	$5250
Clean Long-Duration Storage (FE-air)	$1875	$2500	$3750

Evolving Federal Landscape

Over a 20-year planning horizon, there are always elements of policy uncertainty, and this sensitivity is designed to test how much policy decisions at the federal level impact resource decisions in the region. This felt especially pertinent given the distinct policy shift between administrations that occurred in the early days of this planning cycle. Most of the Ninth Plan will reflect the current administration's policies, because those are the ones currently enacted as law. However, one scenario explores changing hydro operations began analysis before the One Big Beautiful Bill Act was enacted in July 2025, and therefore reflects previous policies.[113]

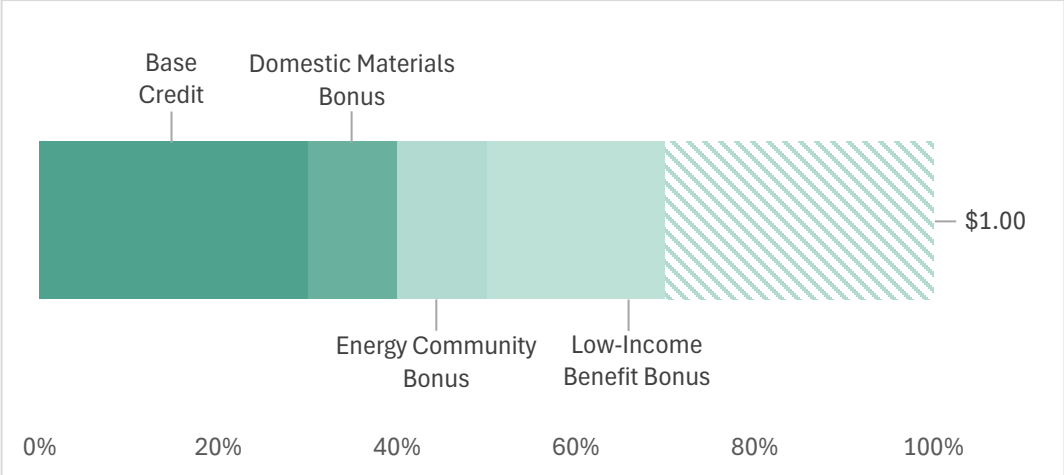
By design, one other sensitivity will not reflect current policy, which is the evolving federal landscape sensitivity. In this sensitivity, new clean resources will receive tax credits, similar to those enacted by the Inflation Reduction Act (IRA). The sensitivity also assumes the new source emissions requirements under the Clean Air Act as updated by the IRA. These tax credits will apply to all non-emitting technologies and the clean air requirements will concern new combined cycle combustion turbines. These assumptions will be based on those from the IRA and would come into effect in 2030. The other sensitivities in the new resource and transmission risk scenario will reflect the current policy landscape without clean tax credits for renewables, specifically wind and solar, or updated emissions requirements. More about the broader application and reasoning of this sensitivity is described in Technical Appendix B – Existing System Parameters and Policies.

Tax Credits

The Inflation Reduction Act (IRA) extended and expanded tax credits for clean generating resources, making tax credits technology neutral and allowing developers to choose between the investment (ITC) or production (PTC) tax credits for their project.

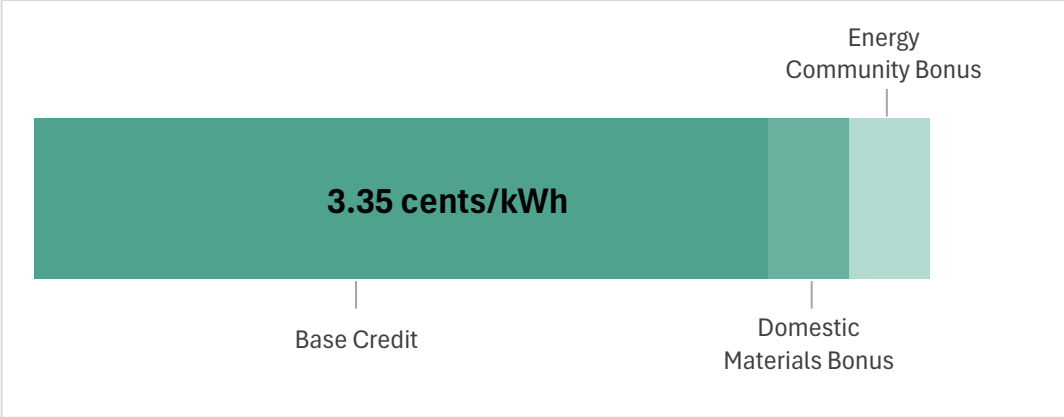
[113] This scenario is described in Technical Appendix N – Scenario Modeling and Results.

Figure G - 73: Investment Tax Credit, Per Dollar Spent on Eligible Project



Per the IRA, resources taking the investment tax credit (ITC) could receive up to 70% back for every dollar spent in the development of the eligible resource. For the plan's purposes, in the evolving federal landscape sensitivity clean resource will receive the 30% base credit. The domestic materials, energy community, and low-income bonus were less universal and more site specific, so they were excluded from modeling of generic resources.

Figure G - 74: Production Tax Credit, Per Kilowatt Produced by Eligible Project

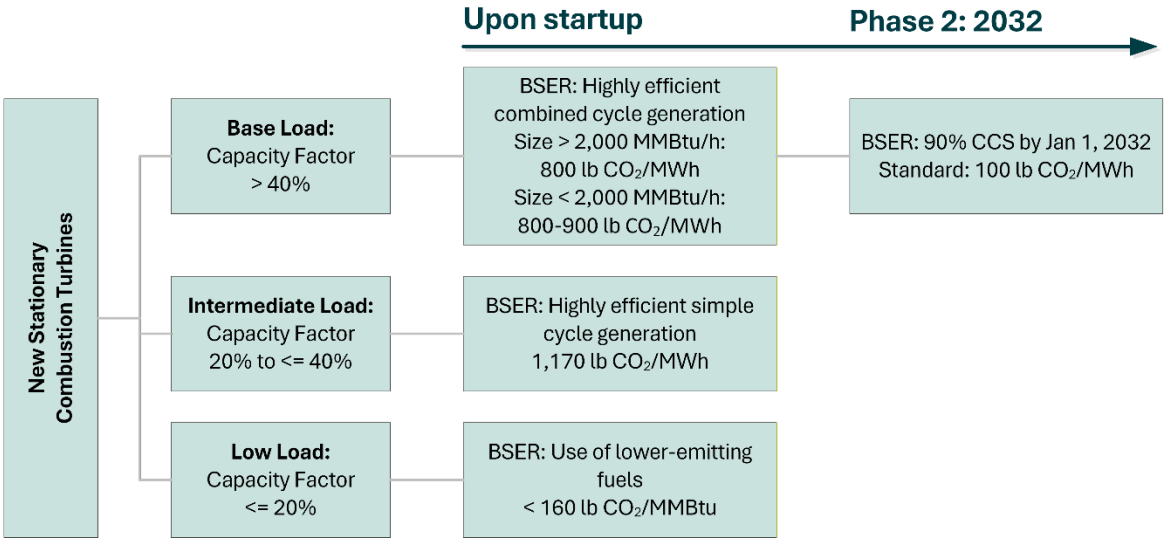


The IRA also made a production tax credit (PTC) available for any clean resource. This means that for the production of 1kW, the producer could get up to 3.35 cents. However, for this sensitivity the Council chose to just model the ITC at the Generating Resource Advisory Committee's recommendation. It was decided that the ITC would be selected more often given how the political volatility of the current moment tends to create uncertainty around the ongoing availability of any tax credits, making the upfront payment of the ITC more appealing.

Clean Air Act Assumptions

Figure G - 75: Clean Air Act 111(b) Standard for New Stationary Combustion Turbines

- Standards effective from date of proposal publication (May 23, 2023)
- Three subcategories: base load, intermediate load, low load
- Standards are technology neutral, affected sources may comply with it by co-firing hydrogen



(Figure adapted from the EPA's Final Standards for New Stationary Combustion Turbines)

The new administration withdrew one other aspect of the IRA pertaining to updates to the Clean Air Act, specifically to 111(b) concerning emissions standards for new stationary combustion turbines. The policy change applied specifically to base load combustion turbines with a capacity factor above 40%, which was read to mean combined cycle combustion turbines, as simple cycles operate a much lower capacity factors traditionally. The updated standard, described in Figure G - 75, requires baseload turbines to adopt 90% carbon capture and storage by 2032. The way this will be represented in modeling for this sensitivity is by limiting the capacity of new combined cycle combustion turbine to below 40% after 2031, as a sort of proxy for the carbon capture, which is still a fairly emergent technology. After the roll-back of the IRA, the standard reverted to best system of emission reduction (BSER). In practice, this means baseload natural gas will be able to operate without any capacity limitations in the other scenarios.

Technical Appendix H: Conservation Methodology and Potential

Contents

Introduction 2
Conservation Supply Curve 3
Developing Conservation Measures 5
Measure Definition 5
Measure Savings Estimates 5
Costs of Conservation 6
Benefits of Conservation 8
Calculating Net Levelized Cost 12
Existing Technology Measures 14
Emerging Technology Measures 16
Other Measures Considered but Not Included 17
Calculating Technical Achievable Potential 18
Potential by Modeling Zone 21
Bundling Conservation for OptGen 22
Adjusting for Load Futures and Scenarios 24
Final Technical Achievable Potential: Supply Curves and Other Charts 26
Economic Potential 35
Excel Workbooks and Tools 35
Supply Curve Materials 35
Supply Curve Analysis Flow 36
File and Folder Structure 36
Where to Find More Information 37

Introduction

The Northwest Power Act requires that conservation (or energy efficiency[1]) be defined as a resource:
"Resource" means –

1. *electric power, including the actual or planned electric power capability of generating facilities, or*

2. *actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure*[2]

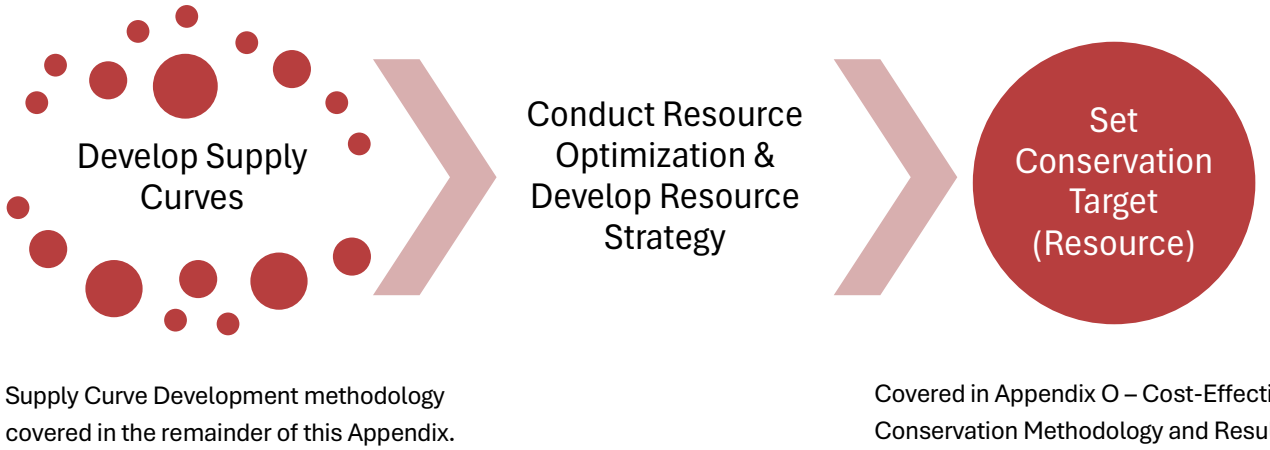
As the Council makes decisions about future resources, it can compare conservation measures and bundles to other available resources, including generating resources, to determine the best resource solutions for the region. Energy conservation reduces demand and can displace the need for new generating resources.

For context, the high-level methodology for estimating the conservation resource is illustrated in Figure H - 1. The first part, "Develop Supply Curves," describes the Council's process for defining the conservation resource so it can be compared with other generating resources and demand-side resources. The development of these supply curves is the subject of the remainder of this appendix. These supply curves are used along with myriads of other parameters, such as generating resource definitions, load forecasts, market conditions, etc. and serve as inputs to the Council's optimization models. The Council considers results from these models and other analysis to develop a resource strategy for the region. A part of this strategy is the cost-effective conservation target. The conservation target, or "economic potential" is described in Technical Appendix O - Cost-Effective Conservation Methodology and Results.

[1] The Council uses the terms "conservation" and "energy efficiency" interchangeably; they both refer to conservation as defined by the Northwest Power Act.

Northwest Power Act, Section 3(19)(A) and (B)

Figure H - 1: Process for Developing the Conservation Resource

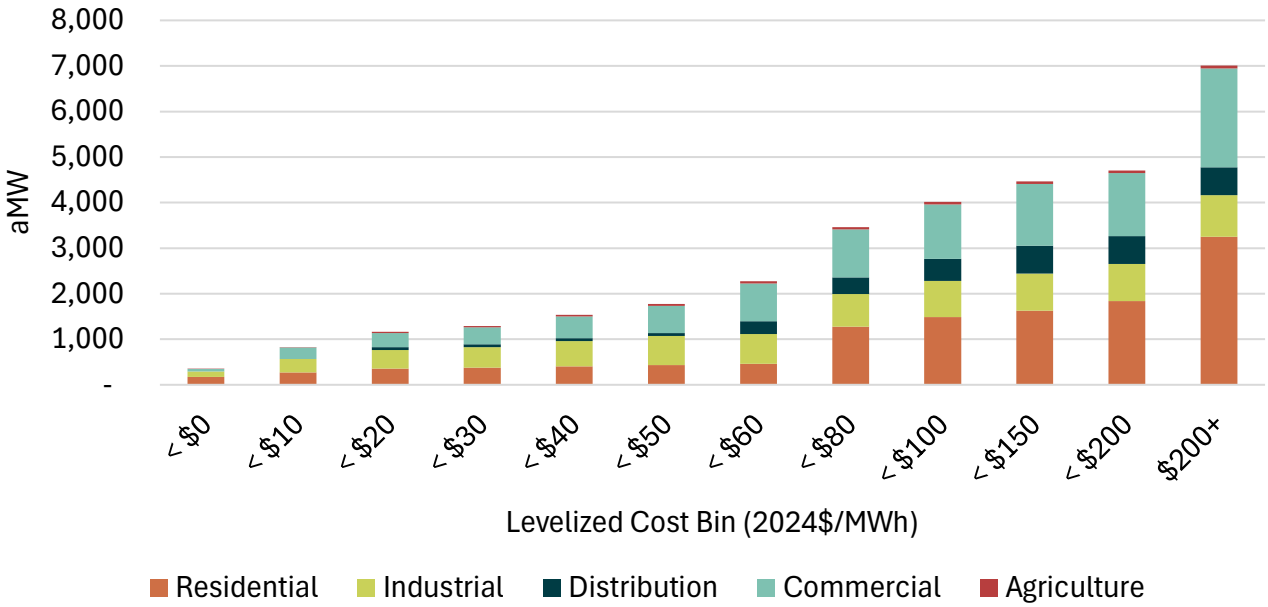


Conservation Supply Curve

Defining the conservation resource requires the compilation of thousands of individual measure applications and bundling them into a format that can be provided to the Council's capital expansion model, OptGen. The measures are compiled into a resource "supply curve." The supply curve groups conservation measures together into levelized cost bins as shown in Figure H - 2. The supply curve in the figure shows all conservation available through 2046, differentiated by sector and by cost bin, for the majority of the Ninth Power Plan analyses. Additional versions of the supply curve used for certain scenarios and load futures are discussed later in the appendix.

Figure H - 2 shows a total of approximately 7,000 average megawatts of achievable conservation potential, as illustrated by the last bar in the far right of the figure. Note that the potential in this chart is cumulative, meaning that each levelized cost bin (e.g., <$40) includes all the potential from the lower cost bins. For example, the chart shows that there is just over 1,000 aMW of conservation potential available for less than $20/MWh. At $80/MWh, the potential jumps to over 3,200 aMW, and the total 7,000 aMW is available with all cost bins included.

Figure H - 2: Conservation Supply Curve



The Council uses levelized costs to compare conservation resources to supply-side resources. The Council uses the Northwest total Resource net levelized Cost (NRC) for its analysis of the cost of conservation measures.[3] This includes all the costs and benefits to reflect the full cost of the measure, regardless of who is paying the costs, as consistent with the definition of system cost in the Northwest Power Act (Section 3(4)(B)). ProCost[4] is the tool the Council uses to calculate the NRC for conservation measures. The levelized cost components are described in detail later in this appendix.

The Ninth Plan conservation supply curves include a wide diversity of both existing and emerging technologies. Existing technologies are available immediately in the Council's planning model, while emerging technologies are available later in the planning period.

The remainder of this appendix provides the detailed methodology for developing the conservation supply curves for the Ninth Plan, provided in four primary parts:

- Developing Conservation Measures
- Calculating Technical Achievable Potential

[3] Note: The Council formerly used the term "total resource cost (TRC)" instead of NRC and updated to avoid confusion with other usages of TRC that are not consistent with the Act.

[4] The ProCost tool was developed to characterize the costs and benefits of conservations measures and programs and produce levelized costs and benefit cost ratios. It is used by the Council to develop the conservation supply curves, and by the Regional Technical Forum to evaluate cost-effectiveness relative to the plan findings. https://rtf.nwcouncil.org/work-products/supporting-documents/procost.

- Bundling Conservation for OptGen
- Adjusting for Load Futures and Scenarios

Developing Conservation Measures

Measure Definition

A conservation "measure" is any device or method that results in electricity savings compared to its baseline. For example, a heat pump will conserve, or reduce, electricity compared with a baseline electric furnace, or adding insulation to a previously uninsulated attic will reduce heating and cooling energy requirements. The Power Act (the "Act") defines conservation as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution."[5] For a measure to constitute conservation under the Act, it must meet both parts of the definition. That is, the measure must reduce electric power consumption, and the reduced consumption must result from an increase in the efficiency of energy use, production, or distribution. A measure that does just one or the other – for example, reduce electricity consumption but not through an efficiency increase – does not qualify as conservation under the Act. For example, turning your thermostat down on cold winter days and wearing more layers of clothing to keep warm is not conservation. It is reducing electricity consumption, but not through a more efficient use of electricity.

The primary component of an efficiency measure is the annual electricity savings (in kilowatt-hours, or kWh) associated with the device or method. Cost and lifetime are two additional key components that define a measure. The measure cost may include a variety of components, including incremental capital costs and operations and maintenance (O&M) costs. All these costs along with some additional benefits are combined to ultimately produce a levelized cost of energy saved (in $/kWh). This section explains all these components.

Measure Savings Estimates

Estimating or measuring the annual kWh savings is the foundational step in developing the supply curves. The starting point for many savings estimates is the Regional Technical Forum (RTF)[6]. Beyond the RTF, measures are identified from the range of measures currently in utility programs, regional programs (e.g., NEEA, Energy Trust of Oregon), federal government programs and standards (e.g., DOE, EPA), utility potential assessments, technical reference manuals (TRMs), emerging technology research, and input from local, regional, and national experts. Once the measures are identified,

[5] Northwest Power Act, Section 3(3).
[6] The RTF is a technical advisory committee to the Northwest Power and Conservation Council that develops standards to verify and evaluate conservation savings.

Council staff seek to identify reliable savings (and cost) data. Savings values are based on engineering estimates, metered data, survey results, laboratory test data, and evaluations from the operation of existing conservation programs.

Conservation measures are defined from three different baseline types: new construction, natural replacement, and retrofit. In the case of new construction, the stock available for the measure depends on the forecast for new additions (e.g., new homes). Natural replacement (or, "lost opportunity") measures depend on the life of existing equipment and assumes the measure is applied at the end of its useful life. Retrofit measures can be installed at any time and the baseline is the on-site conditions. These opportunities are tracked separately over the course of the forecast period and limit the annual availability of conservation opportunities.

Savings values are estimated for each of the new construction, natural replacement, and retrofit baseline types. Measure savings are analyzed on an incremental basis relative to the baseline condition. Incremental measure savings can be different depending on the baseline type. For example, incremental savings of high-performance windows in a new construction application only include the additional savings of the windows compared to what would be required by code. In a retrofit application, the savings values are measured based on the incremental difference between the existing equipment and the new equipment.

For new construction and replacement equipment, baseline conditions are the more efficient of either: (1) the minimum applicable code or standard or (2) current practice, which is the average efficiency of all products sold in the market at the time of purchase. State building codes and federal and state standards for equipment are continually being updated. The baseline assumptions for codes and standards used in the Ninth Plan are those that were adopted by the end of 2023, but which may have effective dates that occur in the future. Both savings estimates and the demand forecast reflect the effective dates of adopted standards. If current practice is more efficient than code, then those assumptions are used. The baseline assumptions for each measure in the analysis are described in the measure workbooks.

Costs of Conservation

Measure Costs

Typically, the largest cost component of a conservation measure is the incremental capital cost. The incremental capital cost includes all upfront costs for purchasing and installing the measure. These incremental costs will be unique for each measure. For example, the cost of an efficient heat pump upgrade measure is typically the difference between the cost of the efficient heat pump minus the cost of the less efficient, current practice heat pump. Cost estimates are identified separately for each of the new construction, natural replacement, and retrofit baseline types. Incremental measure costs can be different depending on the baseline type. For example, incremental costs of high-performance windows in a new construction application only include the additional cost of the windows compared to what would be required by code (or current practice). In a retrofit application,

the labor cost of removing and replacing the existing window is added to the cost, as this is a discretionary decision.

In addition to the incremental costs, the Council includes all other related costs associated with the measure. A measure may have on-going operations and maintenance (O&M) costs (or benefits) compared to the baseline. For example, a heat pump water heater has maintenance costs to clean filters and discharge condensate compared to an electric resistance water heater. The incremental capital and O&M costs are all assumed to be nominally constant throughout the planning horizon. There may also be other fuel costs, such as additional gas heating required when high-efficiency lighting (that produces less waste heat) is installed. Finally, other quantifiable non-energy costs are also included in the cost calculation if they can be sufficiently quantified and are consistent with the environmental methodology for quantifying directly attributable environmental costs and benefits, as defined by the Act. For example, an evaporative cooler might require significant water consumption and these associated water costs compared to a vapor-compression system would be included. Note that many of these other related costs could instead be benefits (negative costs). For more details on these costs (and benefits) see Technical Appendix A – Global Assumptions and Technical Appendix C - Methodology for Quantifiable Environmental Costs and Benefits.

The Council also includes a programmatic administration cost, or "admin cost". The admin cost is the overhead cost (labor) and other related expenses, such as marketing, that are part of executing a utility conservation program. In all prior plans, the admin cost was assumed to be 20 percent of the incremental capital cost. However, for the Ninth Plan, the Council commissioned a study[7] to determine if it could identify enough data to improve on this estimate. This study resulted in the admin costs by sector shown in Table H - 1. The admin costs shown in the table below are multiplied by the first-year annual energy savings of the measure, in kWh, to calculate the final admin cost in dollars.

Table H - 1: Conservation Program Administration Costs by Sector

Residential	$0.16/kWh
Commercial	$0.13/kWh
Industrial	$0.06/kWh
Agriculture	$0.12/kWh
Utility System	$0.12/kWh

Note that tax credits may also be included in the cost assumptions. In general, they would show up as a reduction to the capital cost.

[7] Presentation of findings to the Council's Conservation Resources Advisory Committee available here: https://nwcouncil.box.com/s/b2h5rmekbiyd0545kchzhjzv002nx528.

Financial Assumptions

The present value cost of conservation is determined in part by who pays for it and how it is financed. The Council's Conservation Resources Advisory Committee (CRAC) was asked to provide recommendations on the anticipated "cost-sharing" between utilities and consumers. Council staff also developed estimates of the cost of capital and equity used to pay for conservation based on the mix of consumers in each of the major sectors. These cost shares and finance costs are applied to each cost source for each measure at the time they are incurred.

Utilities and other program operators typically offer incentives to customers (end-users) to purchase and install measures. The Ninth Plan assumes the utility pays 100 percent of the cost for conservation measures. This is a new assumption relative to previous power plans. In past plans, it was assumed that the customer always pays a portion of the cost. This assumption better reflects the treatment of conservation as a resource, since it is the utility that needs to purchase that resource.

The cost of capital varies among residential, commercial, and industrial customers. Financial life is the term over which a sponsor's share of capital cost is financed. However, for the Ninth Power Plan, all the costs for conservation are assumed to be paid for up front, so no financing is needed.

Tax Credits

For some modeling scenarios and sensitivities analyzed in the Ninth Power Plan, federal tax credits are included for measures covered under the 2022 Inflation Reduction Act (IRA). Measures in the Ninth Plan that include these tax credits, for the appropriate sensitivities, include high efficiency heat pumps and weatherization.

As the future availability of tax credits is uncertain, these costs are included for some Ninth Plan scenarios and sensitivities but not all. Table H - 7 in the section Adjusting for Load Futures and Scenarios summarizes which sensitivities include these tax credits and which do not.

Benefits of Conservation

The primary benefit of conservation is its annual electricity savings (kWh) that can be quantified and valued. However, there are other benefits that can be attributed broadly to all measures or in some cases to individual or groups of measures. This section describes these other benefits that are quantified and applied to conservation measures for the Ninth Plan. All the costs and benefits are ultimately included in the net levelized cost calculation described later in this section.

Deferred Transmission and Distribution

The deferred transmission and distribution (T&D) capacity is estimated by the contribution of conservation on winter peak loads, defined as the average over the hours ending 8-9 am on a weekday in December, January, or February and, for summer peak loads, as the average over the hours ending

5-8 pm on a weekday in July and August[8]. By reducing the peak load with conservation, ongoing upgrades or expansions to the T&D system and associated costs are deferred, since the new post-conservation loads are lower. The Council used data from utilities in the region to estimate this value: $11.13/kW-yr for deferred transmission and $19.71/kW-year for deferred distribution (both in 2024$).[9] The Council uses these regional average values but also recognizes that transmission and distribution system cost savings are dependent upon local conditions.

Winter Peak Hours: Hours ending 8-9 am on weekdays in Dec, Jan, Feb

Summer Peak Hours: Hours ending 5-8 pm on weekdays in Jul, Aug

Deferred T&D Values: Transmission = $11.13/kW-yr, Distribution = $19.71/kW-yr

Line Losses

The transmission and distribution power lines incur losses when transmitting electricity from one location to another. These losses need to be accounted for by estimating the difference in savings at the end-use site and the utility busbar.[10] For the Ninth Plan, the Council conducted research[11] and collected data from utilities and the US Energy Information Administration (EIA) to determine the average losses on both the distribution and transmission systems. These values were found to be 2.8 percent for the transmission system and 4.4 percent for the distribution system.

Average Line Losses: Transmission = 2.8 percent, Distribution = 4.4 percent

There are two types of losses on the transmission and distribution system. The first are no-load/core losses, or the losses that are incurred just to energize the system – to create a voltage available to serve a load. Nearly all of these occur in step-up and step-down transformers. The second are resistive losses, which are caused by friction released as heat as electrons move on increasingly crowded lines and transformers. Typically, about 30 percent of the average annual losses are no-load or core losses, and about 70 percent are resistive losses for distribution systems.

Losses increase significantly during peak periods. ProCost, the Council's cost-effectiveness tool, uses the formula for the resistive losses, I^2R, where "I" is the current on any transformer or distribution line, and "R" is the resistance of the wires through which the current flows. While the "R" is generally constant through the year, since utilities use the same wires and transformers all year

[8] These hours were selected by analyzing hourly forecasted loads for 2031.
[9] Technical Appendix A – Global Assumptions provides more information the assumed T&D deferral values for the Ninth Plan.
[10] The starting point for the utility transmission system. The difference between the site and busbar savings are the transmission and distribution losses.
[11] Research findings presented to the Council's Conservation Resources Advisory Committee available here: https://nwcouncil.box.com/s/opdoxu8ullwi3o0uedeodavgekid2ttt.

long, the "I" is directly a function of the demand that customers place on the utility. Thus, resistive losses increase with the square of the current, meaning losses increase as load increases. Depending on the system load shape, the percentage of generation that is "lost" before it reaches the load is typically at least twice as high as the average annual losses on the system. During the highest critical peak hours (perhaps 5-25 hours per year) when the system is under stress, the losses may be four to six times higher than the average.

ProCost uses the system load shape and the conservation measure load shape to calculate the impact of the measure on system losses, accounting for both the core and resistive losses.

Deferred Resource

Conservation measures also have a deferred resource value, though the economic value of this is derived from analysis of resource strategies in the OptGen model rather than fixed as an input. As such, the economic value of a deferred resource was set to zero for developing the supply curves. Instead, the derived economic value of a deferred resource (e.g., deferred generation capacity) is captured in the determination of the plan conservation goals and is used for setting cost-effectiveness levels for conservation measures and programs.

Other Benefits

The other benefits of conservation included in the levelized cost are "other fuel" and quantifiable non-power system benefits. The other fuel benefits are savings in natural gas or heating oil from, for example, increased insulation levels. The homeowner who has air conditioning and a gas furnace will save electricity in reduced cooling usage as well as saving gas from reduced heating usage by adding ceiling insulation. Note that the "other fuel" category can be either a cost or benefit (negative cost).

In addition, the Council includes the value of quantifiable environmental benefits that fit within the Council's environmental methodology. The key one for the Ninth Plan is water savings. For example, by installing an efficient clothes washer, the homeowner will use less water than the baseline equipment. The value of this water reduction is included as a benefit in the net levelized cost calculation.

The Council's 2021 Power Plan called on the RTF to develop a methodology for quantifying the resilience benefit of some conservation measures. Based on this analysis, the Ninth Plan includes a resilience benefit for residential weatherization measures. This benefit, estimated to be approximately $0.002 to $0.008 per annual kWh saved, represents the value that weatherization provides in mitigating and recovering from the negative effects of extreme weather events and/or other electric grid outages.[12]

[12] See methodology and valuation presented to the Council's Conservation Resources Advisory Committee here: https://nwcouncil.box.com/s/pndnd9yyie9j6lbrblq7xgtxxr87166v. Actual resilience value depends on the specific

Resilience Value: $0.002 - $0.008 per annual kWh saved[13]

Northwest Power Act Conservation Credit

Finally, the Northwest Power Act directs the Council and Bonneville to give conservation a 10 percent cost advantage over sources of electric generation.[14] The Council does this by calculating the Act credit as 10 percent of the value of energy saved at wholesale market prices, plus 10 percent of the value of savings from deferring electric transmission and distribution system expansion, deferred generation capacity investment, and risk avoidance. This 10 percent value is included in ProCost for developing the levelized costs.

Regional Power Act Conservation Credit: 10%

There may be other measure benefits or costs that are not quantified in this analysis. The Council's methodology for determining quantifiable environmental costs and benefits outlines the approach taken to determine if a particular non-energy cost or benefit is included in the analysis. See Technical Appendix C - Methodology for Quantifiable Environmental Costs and Benefits for more information.

Value of Conservation with Respect to Time

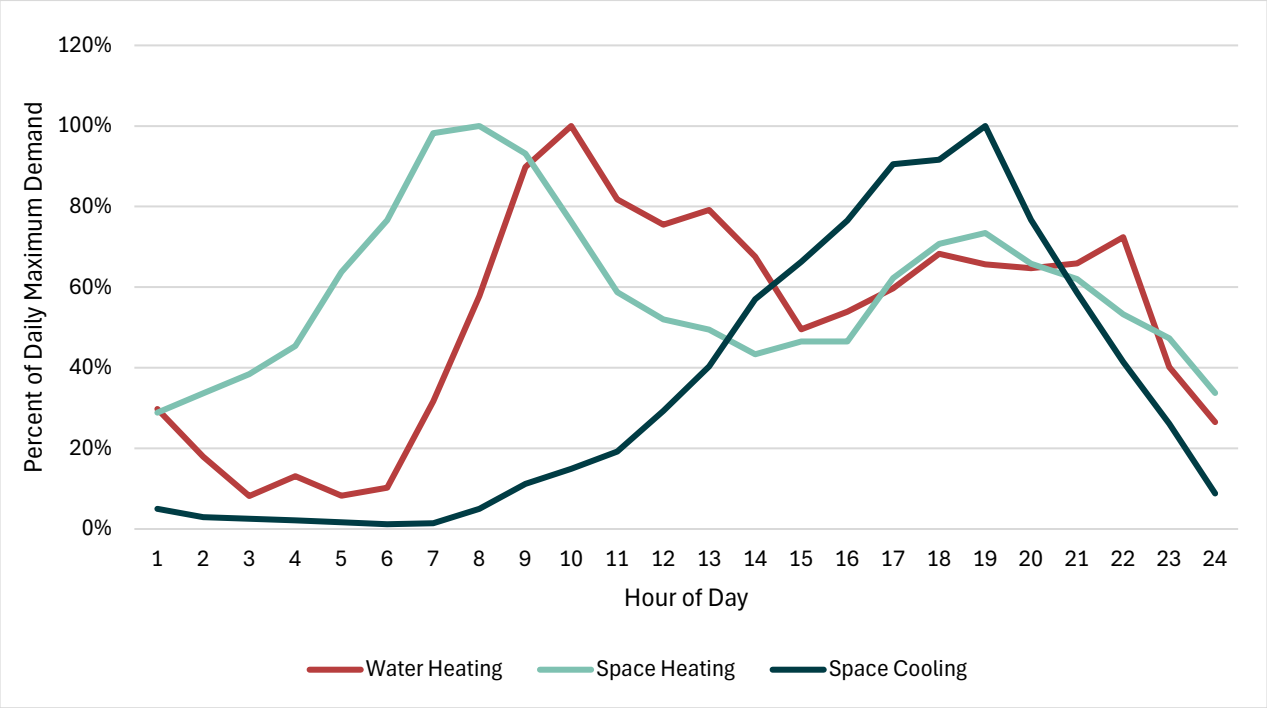
The energy saved from conservation is generally not constant across every hour of the year. For example, efficient street lighting only saves energy from dusk-to-dawn, the hours of which vary over the year. Figure H - 3 shows typical hourly savings profiles for measures that improve the efficiency of space heating, water heating, and central air conditioning in a typical Northwest home. The vertical axis indicates the ratio (expressed as a percentage) of each hour's electric demand to the maximum demand for that end-use over the course of the entire day. The horizontal axis shows the hour of the day, with hour "1" representing midnight to 1 am.

measure and HVAC type but is typically around $0.002/kWh for homes with gas heating, $.0.006/kWh for homes with heat pump heating, and $0.008/kWh for homes with electric resistance heating.

[13] Ibid.

[14] Northwest Power Act, Section 3(4)(D).

Figure H - 3: Illustrative Hour Load Profile for Three Residential End Uses



As can be seen from inspecting the figure above, water heating savings increase in the morning when occupants rise to bathe and cook breakfast, then drop while they are away at work and rise again during the evening. Space heating savings also exhibit this "double hump" pattern. In contrast, central air conditioning savings increase quickly beginning in the early afternoon as the outside temperature rises, peaking in late afternoon and declining again as the evening progresses and outside temperatures drop. Measure savings can also vary seasonally and by day of the week. As the price of electricity varies by day and by season, the value of conservation will also vary, depending on its savings shape.

By reducing the peak load with efficiency, ongoing upgrades or expansions to the T&D system and associated costs are deferred. Of course, each individual conservation measure analyzed has a unique shape, which will affect its value as a resource option and its measure cost-effectiveness.

Calculating Net Levelized Cost

Once all the measures have their costs and benefits identified, the Council uses ProCost to calculate the levelized cost for each. The primary components of the levelized cost are the net present value (NPV) of the measure costs divided by the NPV of the energy savings of the measure. All cost and benefit streams are converted to present-value costs (in 2024$) and benefits based on the financing

costs, sponsor[15] cost shares, and discount rates. ProCost uses standard capital recovery factors and present value factors to calculate present value costs and benefits. Finance costs use sponsor-specific interest rates and terms assigned by user input to calculate the present value of capital costs of measures. Annual costs and benefits that are not financed are counted in the years they occur and discounted to present values using standard present value factors and the global discount rate of 3.70 percent used in all analysis for the Ninth Plan.[16]

Discount Rate: 3.70 percent

ProCost sums all the present value costs and nets out benefits. This value is then amortized over the life of the Plan (20 years) using standard capital recovery factors and the discount rate. The resulting annual "levelized" cost is divided by the discounted annual energy savings adjusted for transmission and distribution line losses to produce a levelized cost per unit energy saved in dollars per MWh.

The NRC represents all costs minus all benefits regardless of which sponsor incurs the cost or accrues the benefits. In addition to energy system costs and benefits, the NRC includes non-energy, program administration, other-fuel, O&M, Power Act credit, and periodic-replacement benefits and costs. The costs and benefits included in the Ninth Plan are summarized in

Table H - 2.

Table H - 2: Costs and Benefits of Conservation

Costs Included	Benefits Netted Out
Capital & Labor	Regional Power Act Credit
Annual O&M	Annual O&M
Program Administration	Deferred Resource Investment[17]
Other Fuel Costs	Other Fuel Benefits
Non-Energy Impacts	Non-Energy Impacts
	Deferred T&D Expansion

While not all these costs and benefits are paid by or accrue to the region's power system, the NRC perspective is used because all costs must be included in resource comparisons and because,

[15] "Sponsors" are those paying for the conservation measure. A sponsor can be the end-user, a retail utility, or BPA, and the shares can be split among the sponsors. For the Ninth Plan the sponsor shares are assumed to be 40% for BPA and 60% for the retail utility. No share is assumed for the customer. See Technical Appendix A – Global Assumptions for more information.

[16] More information on the discount rate is available in Technical Appendix A – Global Assumptions.

[17] The value of a deferred resource may be determined as part of the optimization analysis and is not included in the initial levelized costs in the supply curve.

ultimately, it is the region's consumers who pay the costs and receive the benefits. For some measures, the NRC is less than zero because electric plus non-electric benefits exceed the capital cost of the measure. In addition, the Council's analysis assumes conservation measures comply with environmental regulations and thus incorporate any cost associated with compliance. All costs are assumed to be nominally constant – meaning, the levelized cost is assumed to remain the same throughout the plan horizon.

Existing Technology Measures

The existing conservation technologies considered in the Ninth Plan span across all building sectors and energy end uses. In total, the Ninth Plan looked at over 120 different measures and over thirty thousand individual measure applications. An example conservation measure is residential weatherization. A measure application is a specific and granular implementation of a measure, such as R-49 attic insulation, in a heat pump heated home, in Montana.

Table H - 3 summarizes the existing technology measures analyzed and included in the Ninth Plan.

Table H - 3: Conservation Measures Included in the Ninth Plan by Sector and End Use

Sector	End Use	Measure(s)
Agriculture	HVAC	Stand-Alone Dehumidification, Efficient High-Speed Fans, Efficient High Volume Low-Speed Fans
	Irrigation	Irrigation Hardware, Advanced Irrigation Management, Advanced Irrigation Surveillance, Variable Rate Irrigation, Pump Replacement
	Lighting	Efficient Lighting and Controls
	Motors/Drives	Dairy Vacuum Pump Variable Speed Drives, Dairy Milk Transfer Pump Variable Speed Drives
	Other	Efficient Stock Tanks, Efficient Standby Generator Engine Block Heaters
	Refrigeration	Dairy Plate Milk Pre-Coolers, Dairy Heat Recovery Refrigeration, Dairy Compressor Upgrades
Commercial	Appliances	Dishwashers, Clothes Washers
	Compressed Air	Efficient Compressors
	Electronics	Computers, Monitors, TVs, Servers and Power Supplies
	Food Preparation	Combination Ovens, Convection Ovens, Rack Ovens, Griddles, Hot Food Holding Cabinets, Overwrappers, Steamers, Fryers, Ice Makers, Vending
	HVAC	Efficient Fans, Advanced Rooftop Controls, Packaged Terminal Heat Pumps, Ducted Air Source Heat Pumps, Ductless Air Source Heat Pumps, Chiller Upgrades, Connected Thermostats, Heat Recovery Ventilation, Very High Efficiency Variable Refrigerant Flow with Dedicated Outside Air System (VHE-DOAS), Unitary Air Conditioners, Efficient Windows

Sector	End Use	Measure(s)
	Lighting	LEC Exit Signs, Efficient Lighting and Controls, Street and Roadway Lighting
	Motors/Drives	Efficient Clean Water Pumps
	Other	Efficient Standby Generator Engine Block Heaters, Water Cooler Controls
	Refrigeration	Grocery Refrigeration (Various), Refrigerators, Freezers
	Vehicles	Engine Block Heater Controls
	Water Heating	Efficient Circulator Pumps, Heat Pump Water Heaters
	Whole Building	Energy Management
Distribution	Utility Distribution System	Conservation Voltage Regulation
Industrial	Compressed Air	New Efficient Compressor, Compressor System Upgrade
	Fans and Blowers	New Efficient Fan, Fan System Upgrade
	HVAC	Efficient HVAC
	Lighting	Efficient Lighting and Controls
	Material Handling	Advanced Motors
	Material Processing	Advanced Motors, Industrial Heat Pumps, Cement Process Improvements, Chip Fabrication Process Improvements, Kraft and Mechanical Pulp Process Improvements, Wood and Wood Panel Process Improvements, Water and Wastewater Process Improvements
	Other	Efficient Forklifts, Efficient Standby Generator Engine Block Heaters
	Pumps	Efficient Clean Water Pumps, Pump System Upgrade
	Refrigeration	Advanced Motors, Fast Acting Doors, Refrigeration System Retrofit, Thermal Recovery
	Whole Building	Energy Management
Residential	Appliances	Clothes Washers, Clothes Dryers, Dishwashers, Refrigerators, Freezers, Induction Ovens
	Electronics	Desktops, Laptops, Monitors, TVs
	HVAC	Ducted Air Source Heat Pump (ASHP) Upgrades, ASHP Conversions, ASHP Retro-Commissioning, Ductless Heat Pumps, Ground Source Heat Pumps, Central Air Conditioner Upgrades, Heat Recovery Ventilation, Weatherization (Windows, Insulation, Air Sealing), Duct Sealing

Sector	End Use	Measure(s)
	Water Heating	Efficient Portable Spas, Efficient Circulator Pumps, Heat Pump Water Heaters, Thermostatic Shower Restriction Valves, Wastewater Heat Recovery
	Vehicles	Electric Vehicle Supply Equipment, Engine Block Heater Controls

A full list of measures can be found on the Council's Ninth Plan webpage.[18]

Emerging Technology Measures

The Council included conservation emerging technologies in the Ninth Plan. Like the treatment of emerging generating resources, several proxy conservation measures were defined. These measures are emerging in the sense that either more development is needed or more data/definition, but all are expected to be available at some point during the plan period. The emerging conservation technologies analyzed and included in the Ninth Plan include:

- **Commercial Deep Retrofits**: Reductions in commercial whole building energy use intensities (EUI) using a variety of more efficient building equipment and operations.
- **Commercial Heat Pump Dryers**: More efficient commercial tumble dryers utilizing heat pump technology in laundry applications.
- **Residential Passive House Construction**: A voluntary efficiency standard that requires super-insulated, high-performance building envelopes and other efficiency improvements to significantly reduce HVAC and overall building energy use.
- **Industrial Motor Advancements**: Represents a variety of potential efficiency improvements in industrial motors, including superconducting motors, soft magnetic composite motors, magnet-free motors, trapezoidal radial flux motors, and advancements in nanomaterials and thermal management.
- **Distribution System Efficiency Advancements**: Represents a variety of potential improvements to distribution system efficiency, including transformer right-sizing, feeder balancing, phase balancing, and the addition of regulators and capacitors.
- **Electric Vehicle (EV) Efficiency Advancements**: Efficiency improvements such as lighter materials, better vehicle aerodynamics, more efficient motors and drivetrain components, and reduced electrical losses. The RTF conducted a study to characterize the market for EVs in 2023.

Although some of these technologies are available at the time of the Ninth Plan, many are still fairly nascent in programs.

[18] Full measure list workbook available here: https://nwcouncil.box.com/s/v0iys2vw38t1yz08idtd0xvjce032ky4.

Other Measures Considered but Not Included

There are other conservation measures that the Council considered for the Ninth Plan but ultimately did not include: efficiency measures for large, existing data centers or new data centers; and residential behavior. The following sections provide additional details on why these measures were not included in the Ninth Plan.

Data Center Measures

While data centers represent a significant fraction of expected future load growth, the Council included only a limited set of measures related to small, "embedded" data centers in commercial buildings (ENERGY STAR Servers) and did not include measures for larger and/or new data centers. The reasons for not including measures for these data centers are:

- **Evidence that newer data centers are built very efficiently, especially the largest hyperscale data centers**. This was reflected in a recent data center market study[19] conducted by the RTF in 2024. As power is generally one of a data center's highest costs, the study found that the current practice conservation for new, large data centers is very high.
- **Evidence that energy savings realized in data centers is often counteracted by increases in server processing volume**. While such energy savings may still be considered conservation under the Act, there is little value in modeling a conservation resource when the savings will just be consumed by the facility for additional processing.
- **Lack of data.** The Council believes that there is some conservation potential in the mid-sized data centers such as those in older, rented buildings or in shared spaces with mixed uses. However, there is a lack of data, largely due to the confidential nature of data centers, that prevents the ability to make quality estimates of conservation potential. Northwest utilities are and should continue seeking opportunities for custom efficiency projects (especially HVAC related) in these facilities.

Residential Behavior

The Ninth Plan supply curves do not include a measure for a residential behavior-type efficiency program. Behavior programs are those that send information to utility customers, typically via letter or email, with tips on how to save energy. While some data exists on the energy savings and costs of such programs, there remain challenges and uncertainties that ultimately led the Council staff to not include a behavior measure. These challenges include:

[19] Presentation of data center findings to the RTF in January 2025: https://nwcouncil.box.com/s/5r1ubkq85wees6l5ppr7k53lygulelhz.

- Uncertain underlying drivers of energy savings,
- Unknown overlap between residential behavior savings and savings from other residential efficiency measures,
- Unknown whether behavioral actions meet the Act definition of conservation, and,
- Relatively unknown measure persistence/lifetime.

Calculating Technical Achievable Potential

Once the conservation measures have been defined, the conservation potential can be determined by multiplying the measure savings by the number of measures. In its simplest form, the Council's method for estimating potential is to multiply the measure or unit savings by the number of measures or units. Achievability factors are then applied to obtain what is called the "Technical Achievable" potential.

Technical potential is the amount of conservation that is technically feasible. It considers conservation measures and the number of these measures that could physically be installed, without regard to cost. For example, electricity savings from adding insulation to an attic does not apply to homes with flat roofs or vaulted ceilings (i.e., no attic). Similarly, increasing attic insulation in homes with attics is only applicable from an electric savings perspective if the home is electrically heated. The technical potential can be viewed as the upper limit of what conservation potential is available.

Total technical potential is determined by the per-unit savings multiplied by the number of units in the region. Using an efficient refrigerator as an example, the Ninth Plan estimates the total number of refrigerators per household. This, multiplied by the number of households in the region, will provide the total number of refrigerators within the region. The total regional potential is then calculated by the total number of units times the savings per refrigerator. The physical units differ by sector (see Table H - 4). For the residential sector, the primary physical unit is number of homes by house type, for the commercial sector, floor area of commercial buildings by building type, for the industrial sector, total MWh consumption by industry, and for the agricultural sector, total irrigated acres and dairy milk production.

Table H - 4: Physical Units by Sector

Sector	Primary Physical Unit	# in 2027[20]
Residential	Number of Households (Million)	6.54
Commercial	Building Floor Area (Billion Square Feet)	3.48
Industrial	Total Industrial Electric Consumption (GWh)	33,800

[20]Physical unit data are forecasted to the start year of the Plan, or 2027.

Agriculture	Irrigated Acres (Million)	4.86
	1,000 lbs of Milk	25.5 million
Distribution	Total Regional Electric Consumption (GWh)	195,000

The full set of units can be found in the supporting technical documents on the Council's Ninth Plan web page.[21]

The Council's methodology assumes that once a measure is adopted, it remains in place through the end of the plan (20 years). Each measure has an estimated measure lifetime, and at the end of that lifetime the methodology assumes the measure is re-installed with the same efficiency level. In addition, the annual technical potential accounts for the turnover rate of measures, such as a refrigerator. That is, it is assumed that a refrigerator lasts approximately 15 years, and therefore each year, 1/15 of all refrigerators in the region are replaced.

The number of available units is a function of technical applicability and measure saturation. Technical applicability includes the fraction of stock that the measure applies to and any overlap with mutually exclusive measures. Existing measure saturation reflects the fraction of the applicable stock that has already adopted the measure and for which savings estimates do not apply.

The achievable potential is the technical potential multiplied by two factors: the maximum achievable limit and the ramp rate. The maximum achievable limit assumes a maximum amount of the total potential that could be acquired over the 20-year plan period. This maximum amount assumes that there will be some portion of non-adopters within the plan period, e.g., buildings where the owner has no interest in improving. This maximum achievable fraction was set to 85 percent for all retrofit measures and between 85 and 95 percent for lost opportunity measures. The determination of the upper limit was based on the recent activity around federal appliance standards (more regular updates results in a higher maximum achievability) or the speed of the market change (fast moving markets have higher maximum achievability). For retrofit measures, the 85 percent value has been the traditionally accepted value since the Council's Second Power Plan and was derived from a program called the "Hood River Conservation Project (HRCP)." The HRCP, a $20 million program operated in the early 1980s installed, for free, any weatherization measures that a household energy assessment showed were within a prescribed cost threshold. The program achieved a high response rate for home energy assessments (91% of all eligible participants) and for the subsequent implementation of conservation measures (85% of all eligible participants).[22]

[21] See "9P-Units", available as part of the conservation supply curve supporting documents here: https://nwcouncil.box.com/v/ninthplanEEsupplycurves.
[22] https://eta-publications.lbl.gov/sites/default/files/lbnl-3960e-hrcp.pdf.

Maximum Achievability Limits: 85 - 95%

The second achievability factor is the ramp rate, or "annual deployment limit", which represents the upper limit of annual conservation resource acquisition based on implementation capacity. Such constraints include the relative ease or difficulty of market penetration, regional experience with the measures, likely implementation strategies and market delivery channels, availability of qualified installers and equipment, the number of units that must be addressed, the potential for adoption by building code or appliance standards, and other factors.

The annual ramp rates used in the Ninth Power Plan are illustrated Figure H - 4: Retrofit Ramp RatesFigure H - 4 and Figure H - 5 below. Figure H - 4 illustrates ramp rates used for retrofit measures. These ramp rate values represent the percentage of the stock that can adopt a measure within a given year. The ramp rates represent a wide range of adoption rates from a very slow pace initially (e.g., Retro1Slow) which starts at about one percent of the stock and increases to ten percent midway through the plan. Conversely, Retro50Fast assumes nearly 50% of the stock can be adopted in the first Plan year and approximately 20% of the achievable stock in the second year and then declines rapidly. Figure H - 5 illustrates ramp rates used for lost opportunity measures, which include both new construction and natural replacement measures. Lost opportunity ramp rate values represent the percentage of new or existing construction turnover (for natural replacement measures) that can be achieved within a given year. For example, the fastest lost opportunity ramp rate, "LO80Fast", assumes that nearly 80% of new builds or existing turnover can be achieved in the first year, while some of the slowest lost opportunity ramp rates assume that close to 0% can be achieved in year one.

Figure H - 4: Retrofit Ramp Rates

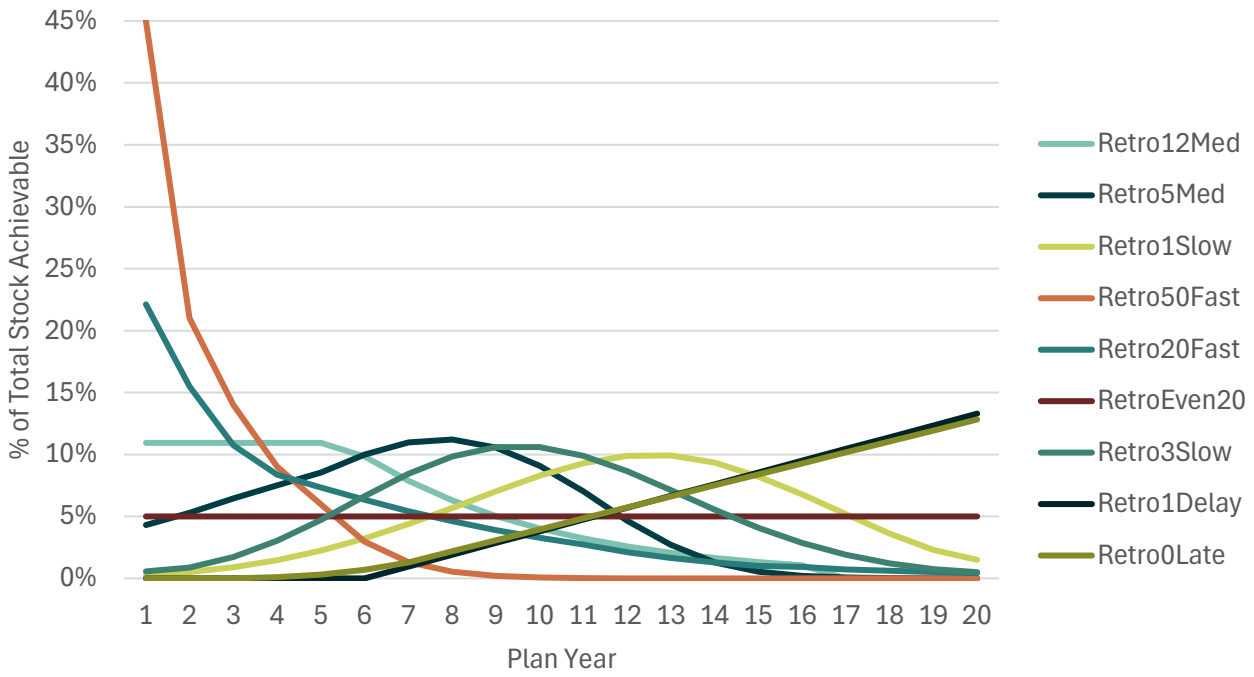
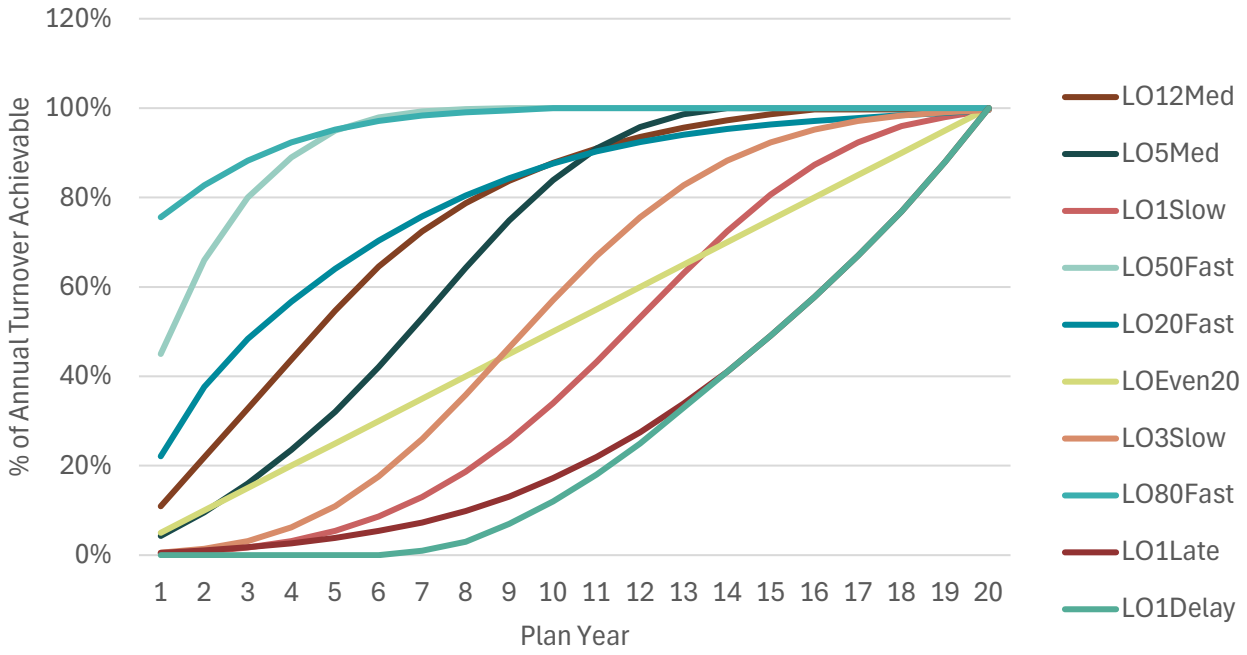


Figure H - 5: Lost Opportunity Ramp Rates



This family of ramp rates is applied to all the measures to reflect the pace of acquisition over the 20-year plan period. Measures for which there is an established infrastructure or for which the market is rapidly changing are given a faster ramp rate, while measures that are newer in the region, or that have experienced sluggish adoption rates, are assigned a slower ramp rate. Specific measures and their associated ramp rates can be found in the Excel workbooks used to develop the supply curves - please see the "Excel Workbooks and Tools" later in this appendix. The annual ramp rate multiplied by the total number of units available each year provides the maximum annual technical achievable potential. The Council also considers region-wide conservation program accomplishments when developing these ramp rates to help align early year potential with recent historic accomplishments.

Potential by Modeling Zone

In previous power plans, conservation potential was estimated only at the granularity of the entire Council planning region. While this represents an accurate picture of the region's overall conservation availability, it cannot represent potential differences in the types of conservation available on a sub-regional level or in the value of conservation on a sub-regional level. For example, some sub-regions of the Council's overall planning region may be willing to pay higher prices for conservation, given the unique characteristics and constraints of their sub-region.

For the first time, the Ninth Plan estimates conservation potential for a set of seventeen smaller sub-regions or "modeling zones." The modeling zones, summarized in Table H - 5, correspond approximately to the Northwest balancing authorities, or portions of balancing authorities. However,

their main purpose is to approximately reflect where different types and magnitudes of conservation are distributed across the region.

Table H - 5: Modeling Zones

Modeling Zone Name	Modeling Zone Abbreviation
Avista Utilities	AVA
Bonneville Power Administration, Idaho and Montana	BPA_IDMT
Bonneville Power Administration, Oregon	BPA_OR
Bonneville Power Administration, Washington	BPA_WA
Chelan County PUD	CCPUD
Douglas County PUD	DCPUD
Grant County PUD	GCPUD
Idaho Power Company	IPCO
NorthWestern Energy	NWMT
PacifiCorp, East	PACE
PacifiCorp, West	PACW
Portland General Electric	PGE
Puget Sound Energy, Central	PSE_Central
Puget Sound Energy, North	PSE_North
Puget Sound Energy, Olympia	PSE_Olympia
Seattle City Light	SCL
Tacoma Power	TPWER

The method in which total conservation potential is allocated to the various modeling zones depends on the type of data available and relevant for the conservation sector and measure. For example, for some dairy conservation measures, county-level cattle data is aggregated to the modeling zone level and used as the basis for estimating zone-level conservation. For most residential conservation measures, housing stock data aggregated at the modeling zone level was used. Other data sources used for the purpose of allocating conservation to the modeling zone level include energy sales and customer data, by state and balancing authority, reported by the US Department of Energy's Energy Information Administration (EIA).

Bundling Conservation for OptGen

For modeling conservation in the Council's capital expansion model (OptGen), it is necessary, as with prior power plans, to aggregate or bundle conservation measures together to represent larger

resource options for the model to select. In prior plans, the sole criteria used to bundle conservation was cost – measures within the same levelized cost "bin" were aggregated together.

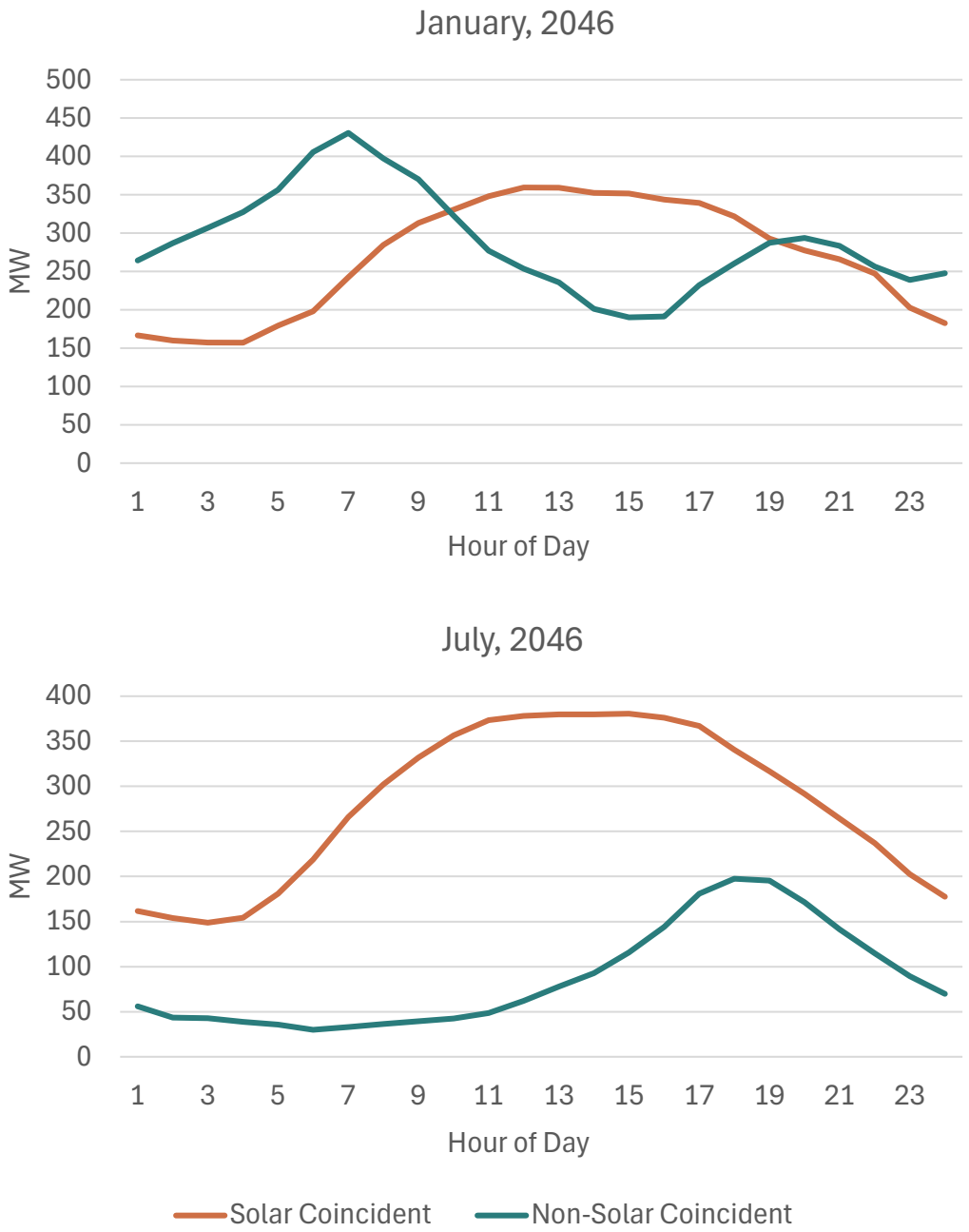
For the Ninth Plan, the additional granularity offered by the OptGen model, both in terms of sub-regional modeling zones and hourly modeling capabilities, allows additional factors to bundle conservation for modeling. The ultimate bundling strategy for the Ninth Plan utilizes three factors to aggregate conservation measures and includes modeling zone, levelized cost, and hourly savings shape type. There are seventeen modeling zones, ten levelized cost bins, and two hourly shape types, resulting in 340 total possible conservation bundles. The bins are summarized in Table H - 6.

Table H - 6: Conservation Modeling Bins

Modeling Zone Bin	Levelized Cost Bin	Hourly Shape Type Bin
AVA	≤ $20	Solar Coincident
BPA_IDMT	> $20 - $40	Non-Solar Coincident
BPA_OR	> $40 - $50	
BPA_WA	> $50 - $60	
CCPUD	> $60 - $70	
DCPUD	> $70 - $80	
GCPUD	> $80 - $100	
IPCO	> $100 - $150	
NWMT	> $150 - $250	
PACE	> $250	
PACW		
PGE		
PSE_Central		
PSE_North		
PSE_Olympia		
SCL		
TPWER		

The hourly shape type is also a new addition for the Ninth Plan, and it is designed to test whether conservation with a certain hourly shape (i.e., capacity characteristics) is more or less valuable to the system. The shape types used in the Ninth Plan are largely reflective of when forecasted market prices are expected to be higher or lower, which is generally correlated to when solar production is available or not. For example, conservation that is largely coincident with solar production and lower market prices may be less valuable to the system than conservation that is providing capacity and energy savings during the early morning or nighttime. Figure H - 6 shows an example of what the two conservation shape types look like that are used in the Ninth Plan.

Figure H - 6: Conservation Shape Types Used for Bundling in the Ninth Plan



Adjusting for Load Futures and Scenarios

There is ultimately not a single set of conservation supply curves for the Ninth Plan, but rather many variations, depending on the load future and analysis scenario being run in the model. Load futures and scenarios are similar in that they can both have changing assumptions that alter the shape,

magnitude, and/or costs of the conservation supply curves; however, they are different in that all load futures are present in every scenario, whereas each scenario is distinct from one another.

Table H - 7 summarizes the adjustments made to the conservation supply curves, depending on the specific load future and scenario. As the table highlights, there are four main drivers of change for the supply curves, depending on the load future and scenario, and they are: the presence of high building electrification, the presence of tax credits, the presence and cost of emerging technologies, and whether there is any assumed delay in conservation availability.

Table H - 7: Adjustments to Conservation Supply Curves for Ninth Plan Scenario Modeling

Analysis Sensitivities	High Electrification	Tax Credits Included	Emerging Tech Included	Availability Delayed
Changing Hydro Operations, Evolving Federal Landscape	No	Yes	Yes	No
	Yes	Yes	Yes	No
Constrained World	No	No	No	No
	Yes	No	No	No
Emerging Tech Uncertainty	No	No	Yes (50% Higher Cost)	No
	Yes	No	Yes (50% Higher Cost)	No
	No	No	Yes (25% Lower Cost)	No
	Yes	No	Yes (25% Lower Cost)	No
Transmission Availability Uncertainty, Short-Duration Storage Limitations	No	No	Yes	No
	Yes	No	Yes	No
Demand Side Resource Limitations	No	No	Yes	Yes
	Yes	No	Yes	Yes

The first driver, "High Electrification," is a function of the load futures, and therefore, its effect shows up in every scenario. For context, the load futures contain a wide range of potential future load trajectories,[23] and most relevant for conservation, some of these trajectories have lower (status quo) building electrification and some contain significantly higher electrification. As more loads are electrified, there is more conservation potential relative to the current practice baseline; therefore, load futures with higher building electrification will have higher available conservation. Note that

[23] Technical Appendix F – Electricity Demand Forecast provides more information on the approach to the load forecast and its multiple trajectories to capture future load growth uncertainty.

higher electrification loads are only assumed for cooking, water heating, and space heating end uses, in residential and commercial buildings, in Oregon and Washington.[24]

The remaining three drivers shown Table H - 7, relating to tax credits, emerging technologies, and delayed conservation availability, are all a function of the scenario modeling, and therefore their effects are isolated to each individual sensitivity. The sensitivities are designed to examine how conservation, and other demand and supply side resources, may be selected differently depending on several different important factors, such as:

- whether or not federal tax incentives are available for certain conservation measures;
- whether or not certain emerging technology measures become available, or if emerging technology prices are higher or lower than expected; and
- whether conservation measures are available according to the timeline assumed in the starting point.

Technical Appendix N – Scenario Modeling and Results provides more information on the specific assumptions in each scenario.

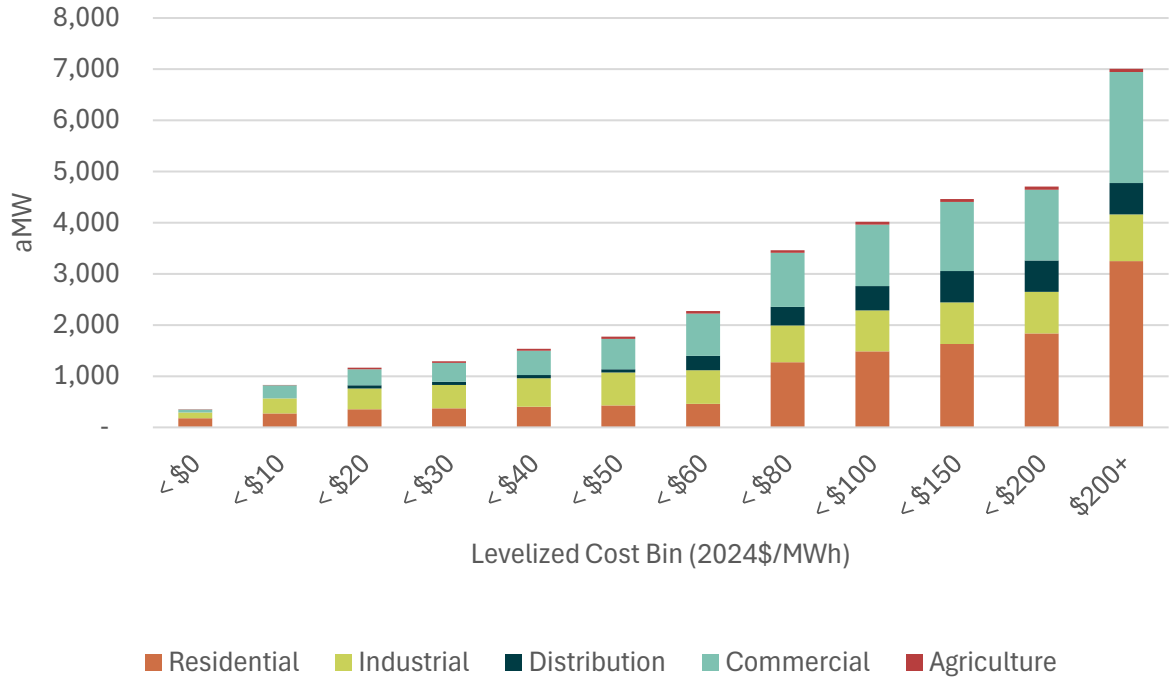
Final Technical Achievable Potential: Supply Curves and Other Charts

All the work described thus far in this appendix results in a final technical achievable conservation resource that is used to compete against other demand and supply side resources in the Council's capital expansion model. The final conservation resource can be represented by a supply curve, that shows the cumulative conservation potential available up to a given price point, in this case the net levelized cost. Figure H - 7 shows the final Ninth Plan technical achievable conservation supply curve for the majority of sensitivities, by sector, over the 20-yr period from 2027 to 2046. Each levelized cost bin is cumulative and includes all the potential from lower cost bins. The curve indicates, approximately:

- ~ 7,000 aMW of total potential from all cost bins;
- ~ 4,000 aMW of potential up to ~ $100/MWh;
- ~ 2,000 aMW of potential up to ~ $60/MWh; and
- ~ 1,000 aMW of potential up to ~ $20/MWh.

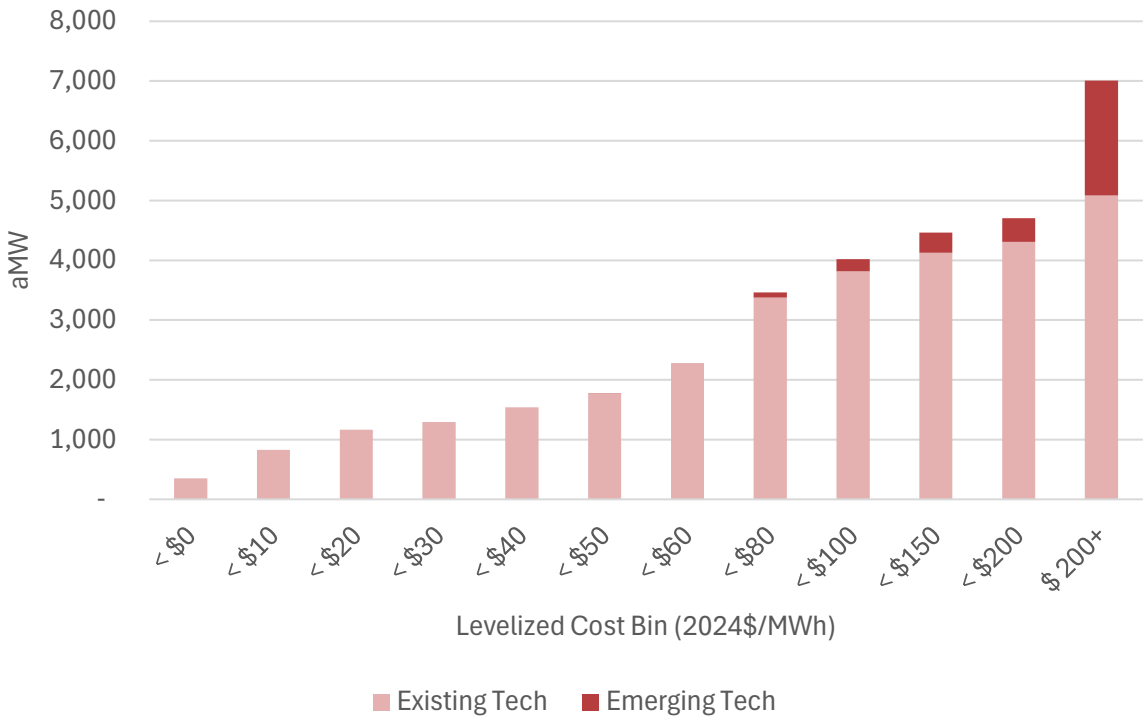
[24] Consistent with the Ninth Plan load forecast.

Figure H - 7: Final Ninth Plan Conservation Supply Curve



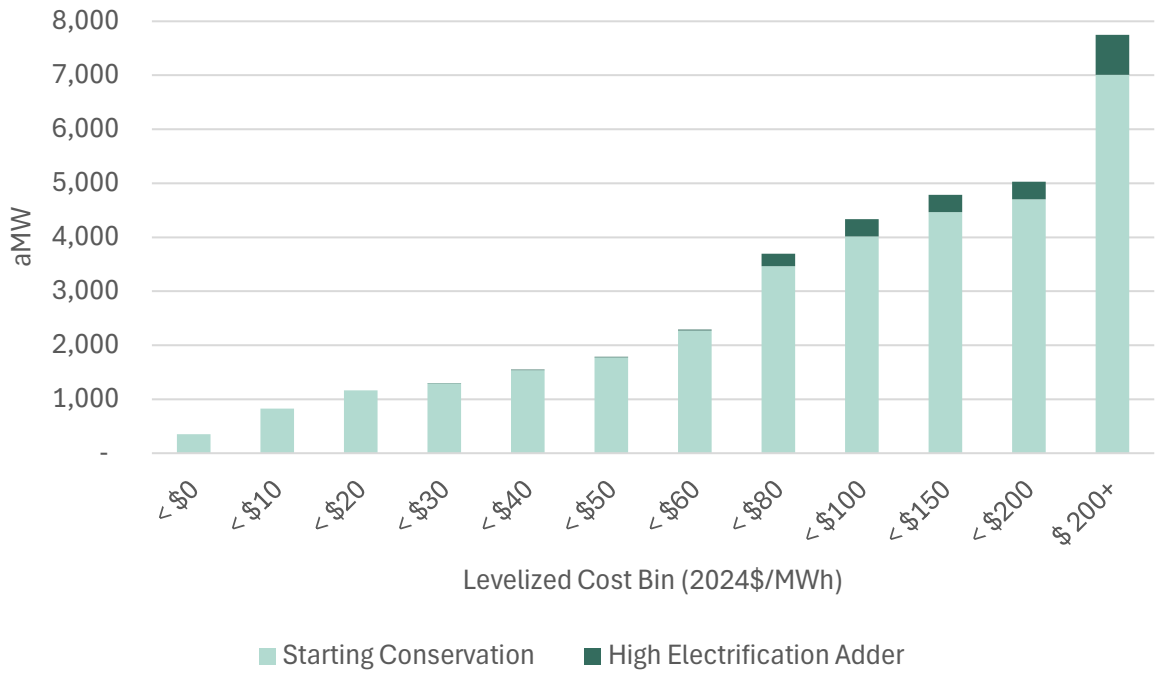
Emerging technologies do make up a significant portion of the conservation supply curve, particularly in higher cost bins and in later Plan years. Figure H - 8 shows that existing technologies make up approximately 5,000 aMW of the total 20-yr conservation potential, while emerging technologies make up the remaining ~2,000 aMW.

Figure H - 8: Emerging Technology in the Supply Curve



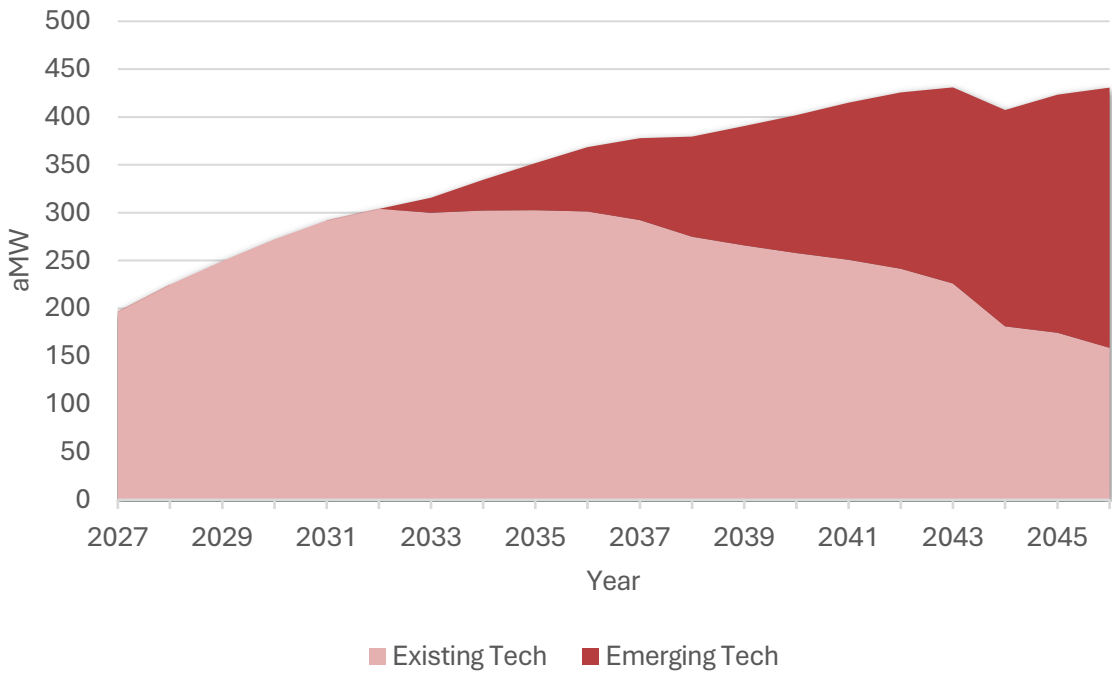
Recall that in load futures with high building electrification, additional conservation resources are available for residential and commercial cooking, water heating, and space heating in Oregon and Washington. In those futures, the Council estimates approximately 740 aMW of additional conservation resource available, as shown in Figure H - 9.

Figure H - 9: Conservation Supply Curve with Higher Electrification



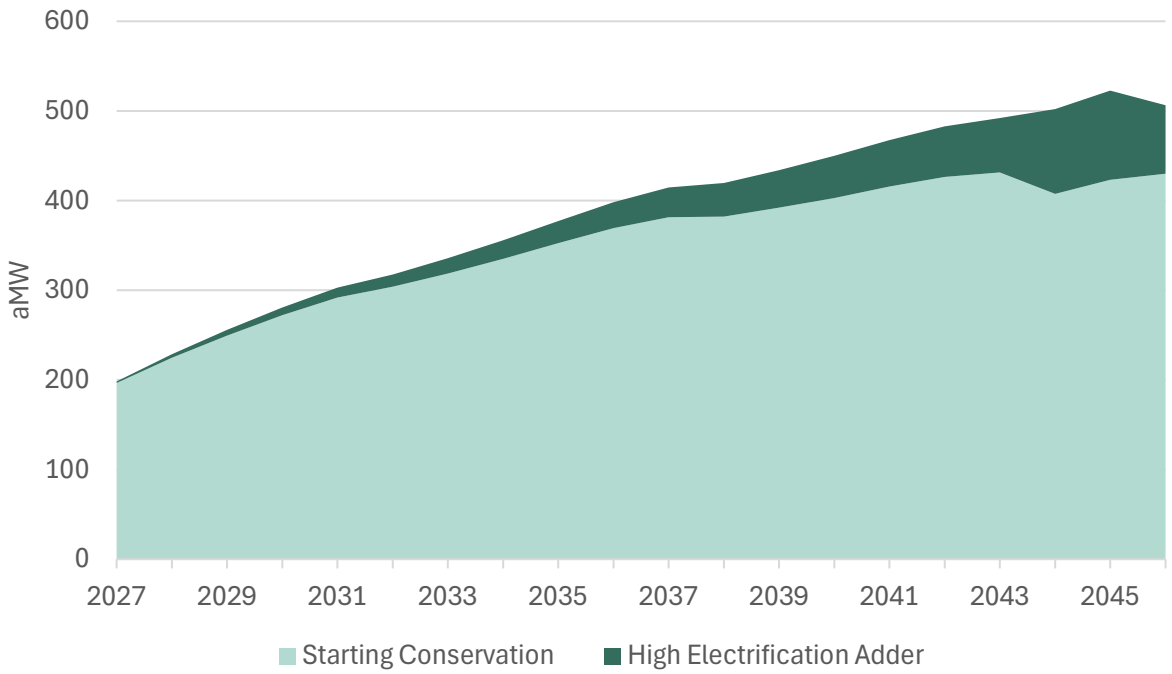
In addition to the cumulative supply curve, it is also informative to represent the conservation resource as incremental conservation available every year over the 20-year period. The incremental conservation available every year depends on a variety of factors, such as the assumed measure ramp rates and stock turnover. Figure H - 10 shows the incremental conservation available every year over the 20-year horizon from 2027 to 2046. Existing and emerging technologies are shaded differently to show that emerging technologies are assumed to appear starting in year seven and make up a significant portion of conservation potential overall, particularly in the "outer years" beyond 2040. Note that the dark shaded portion of this chart representing emerging technologies would not be available in the "Constrained World" sensitivity, where resources are more broadly limited. Also note that this version of the graph does not include additional conservation from high electrification.

Figure H - 10: Annual Incremental Conservation



The additional conservation available in high electrification load futures can be layered on top of the yearly incremental potential to show the total incremental potential, by year, available in those high electrification futures. Figure H - 11 shows the "High Electrification Adder," in darker shading, relative to the starting conservation potential. As the figure illustrates, the additional electrification potential is relatively small in early years but becomes a significantly larger portion of overall potential during the later Plan years. This pacing is mostly driven by the relatively slow rate of equipment turning over in the existing building stock.

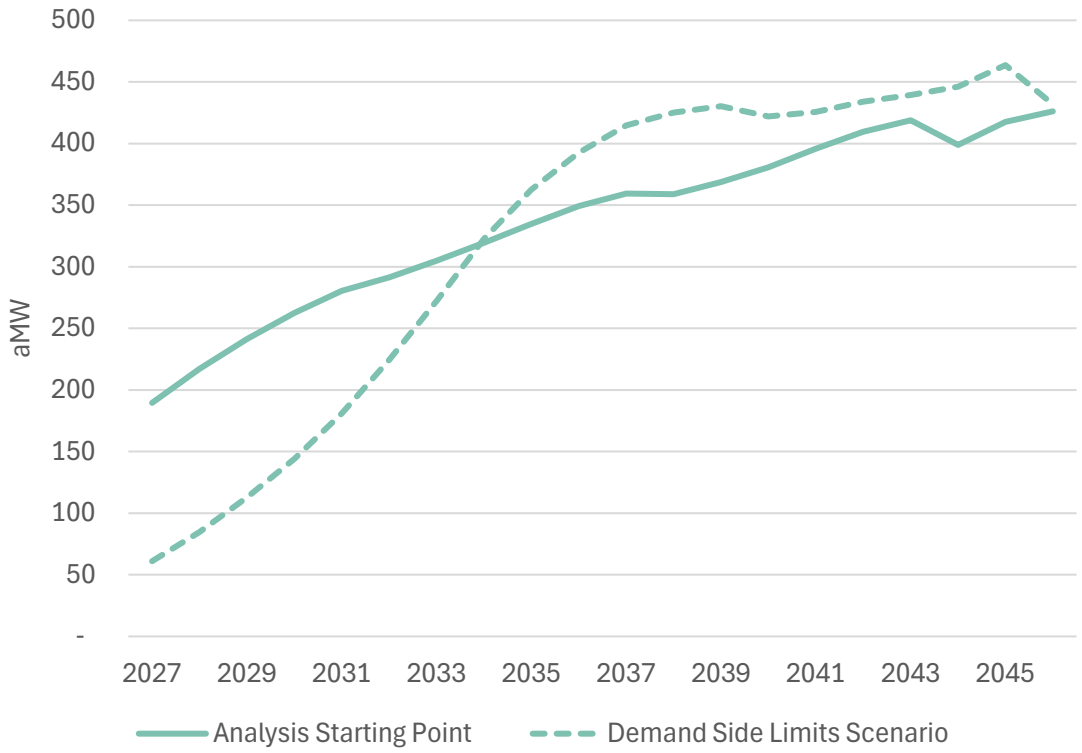
Figure H - 11: Annual Incremental Conservation Including Electrification



One additional factor that is used to vary the incremental conservation available each year is the assumed ramp rate for each measure. For all Power Plan sensitivities, except for one, the assumed conservation ramp rates are the same; however, for one sensitivity, "Demand Side Resource Limitations", ramp rates are assumed to be slower for all conservation measures, to test how resource selections may differ if demand side resources like conservation were not available at the pace assumed in the analysis starting point. Figure H - 12 shows the difference in incremental annual conservation available in the analysis starting point versus the Demand Side Resource Limitations scenario.

Notice that by the end of the 20-Yr Plan period, the two lines in Figure H - 12 reach approximately the same point and have the same approximate areas under their curves. The main difference between them, however, is how quickly they can ramp to reach that potential. In the first six years of the plan period, the Demand Side Limitations sensitivity has only about one third to one half the annual conservation available as compared to the initial supply curve. This is a significant difference, particularly if the region needs resources earlier in the plan period.

Figure H - 12: Annual Incremental Conservation Compared to Demand Side Resource Limitations ("Demand Side Limits") Sensitivity



Finally, it is possible to represent the final set of conservation supply curves, and annual incremental conservation curves, used across all Ninth Plan sensitivities. The final supply curves for all sensitivities are shown in Figure H - 13. Note that this figure uses the final levelized cost bin definitions summarized in Table H - 6**.** The final annual incremental conservation curves for all sensitivities are shown in Figure H - 14.

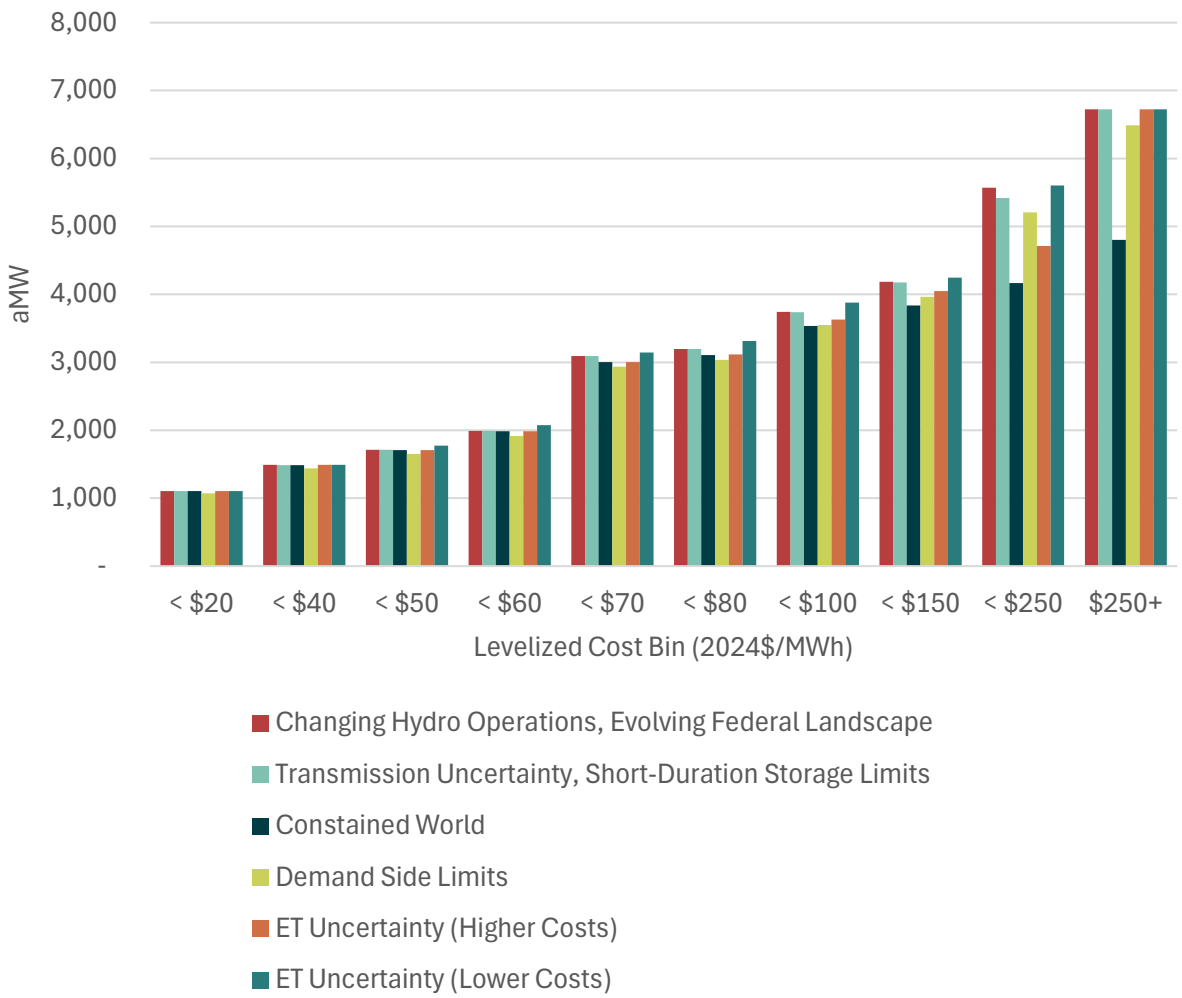
Figure H - 13 illustrates that the conservation supply curves, at least from this 20-yr cumulative view, are relatively stable across Ninth Plan sensitivities, particularly in the lower cost bins. This is largely due to the fact that many of the sensitivities alter assumptions about emerging technologies, which generally reside in the higher cost bins. Sensitivities affecting tax credits also have a relatively limited impact on the supply curves overall, as these credits apply only to a subset of conservation measures in the residential sector[25]. In addition, those measures eligible for tax credits tend to reside in the higher cost bins.

The sensitivity that looks the most different than the others, the "Constrained World", has such a large reduction in potential, because this sensitivity removes all emerging technologies for both demand and supply resources from the analysis – and recall that emerging technologies represent

[25] These measures include high efficiency heat pumps and weatherization.

approximately 2,000 aMW of potential by the year 2046. The are other differences apparent in Figure H - 13, however, all of them are less stark than the Constrained World. For example, in the sensitivity "ET Uncertainty (Higher Costs)" (where ETs cost 50% more than expected), Figure H - 13 shows that there is significantly less potential available at the < $250 bin, and all of that potential has moved to the > $250 bin.

Figure H - 13: Final Set of Supply Curves Used Across All Ninth Plan Sensitivities



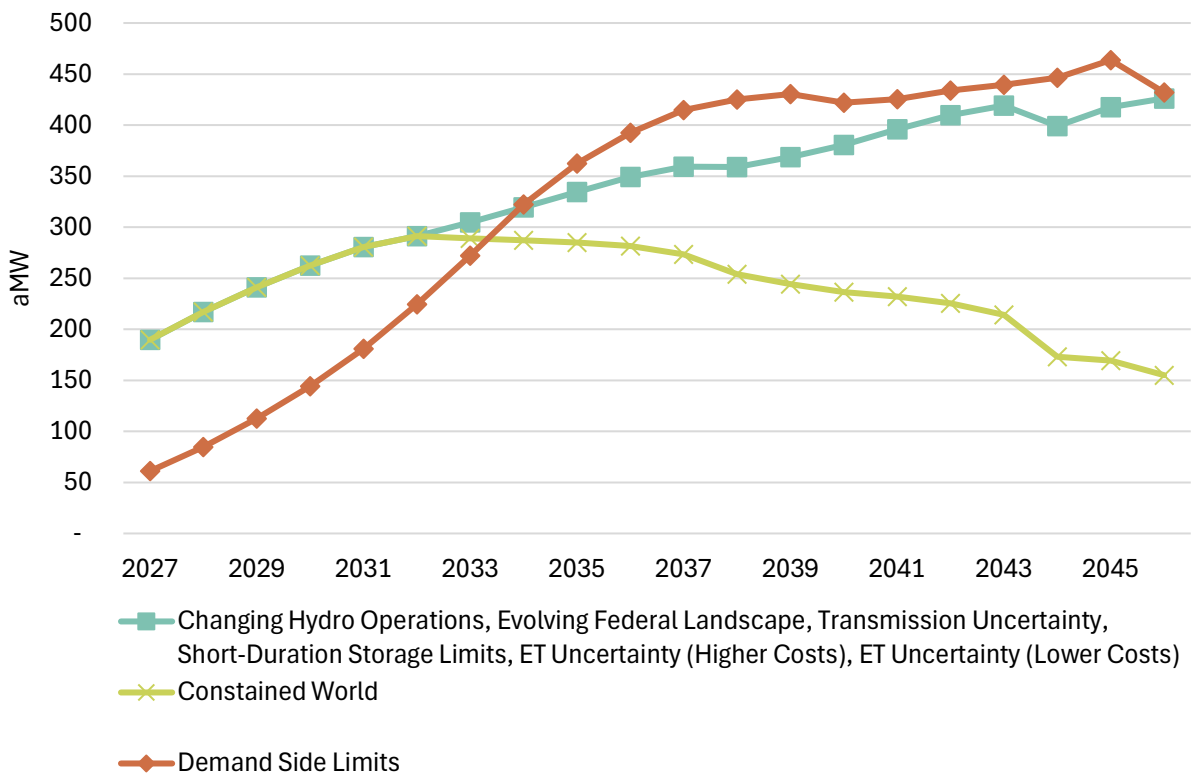
Note that the total potential reached in Figure H - 13 is slightly less than that shown in Figure H - 7, because of the way that Conservation Voltage Reduction (CVR) versus Demand Voltage Reduction (DVR) are modeled in OptGen. Since CVR and DVR are essentially the same technology,[26] the CVR savings are removed from the conservation supply curves in Figure H - 13, so that OptGen can apply

[26] With the main difference being that CVR is DVR that runs all the time.

DVR whenever the model selects it,[27] therefore, ensuring no double-counting of CVR and DVR. Also note that the effect of high electrification is not shown in Figure H - 13.

The annual incremental conservation corresponding to all Ninth Plan scenarios is shown in Figure H - 14. First note that the annual incremental conservation does not differ for all sensitivities. This is because some sensitivities affect costs alone, and do not affect either total or annual conservation acquisition. Therefore, the annual incremental conservation curves for many of the Ninth Plan sensitivities are the same.[28] The major differences in annual incremental conservation potential arise from two specific sensitivities: the Constrained World and the Demand Side Limits. For the Constrained World, the absence of ETs does not affect conservation potential in the first six years, but significantly limits it in years seven through twenty, when ETs are available. Conversely, for the Demand Side Limits sensitivity, conservation potential is significantly reduced in the first six years (by approximately 50 to 66%), but significantly increases in pace after year six.

Figure H - 14: Annual Incremental Conservation Across All Ninth Plan Sensitivities



[27] Including running DVR all the time, which would be interpreted as a model preference for CVR.
[28] Namely, the scenarios: Changing Hydro Operations, Evolving Federal Landscape, Transmission Uncertainty, Short-Duration Storage Limits, ET Uncertainty (Higher Costs), and ET Uncertainty (Lower Costs).

Economic Potential

The Economic Potential is the result of the optimization modeling and final decision making by the Council and is covered in Technical Appendix O – Cost Cost-Effective Conservation Methodology and Results. Once the target has been set, the final cost-effectiveness methodology for the plan is defined. The cost-effectiveness methodology utilizes results from the modeling process to define various avoided cost components so that each current and future conservation measure can be evaluated relative to the next available resources identified in the Plan's resource strategy.

Excel Workbooks and Tools

Supply Curve Materials

The general structure of the Ninth Plan conservation materials consists of three different types of files:

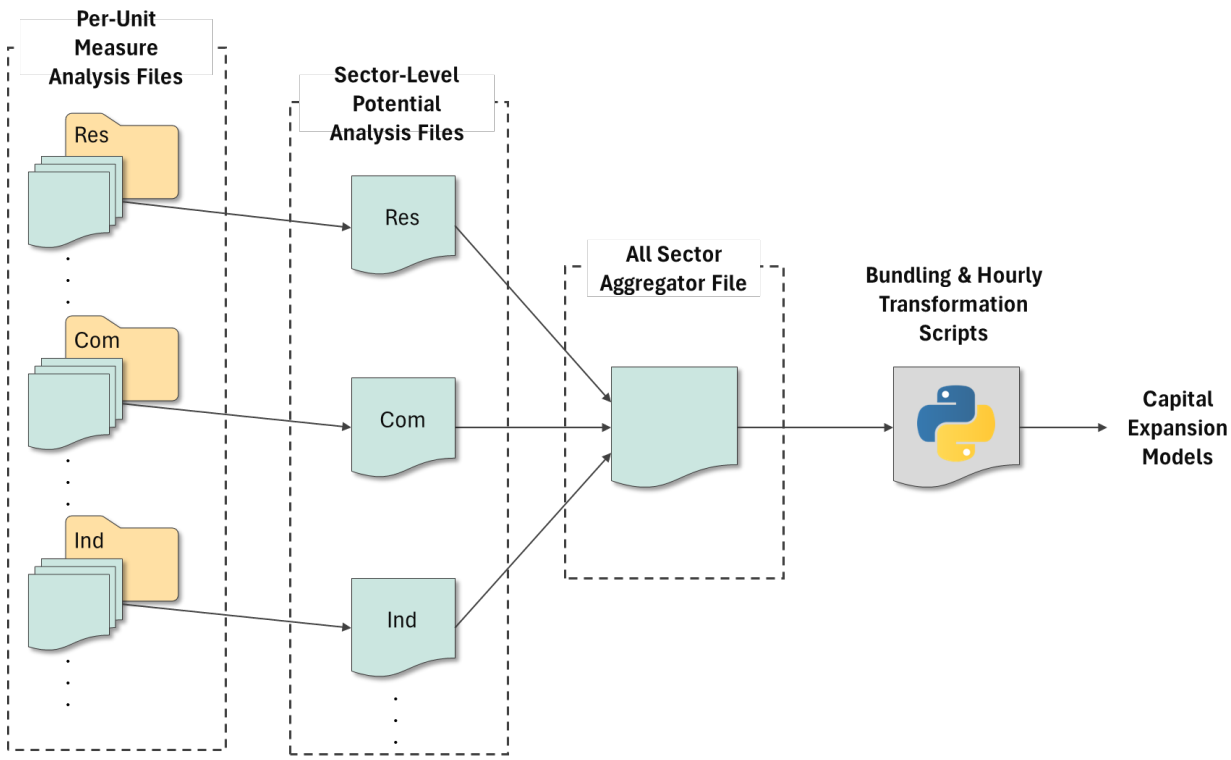
- **Per-Unit Measure Analysis Files**: These files contain the energy savings and cost analysis for one unit of a given conservation measure. For example, if a user were interested in how much energy a single residential ductless heat pump saves, or the methodology used to estimate those energy savings, they would want to look for the per-unit measure analysis for residential ductless heat pumps.
- **Sector Level Potential Analysis Files**: The sector level potential analysis files are where regional conservation potential is ultimately estimated. They accomplish this by:
    - extracting all the relevant data from the per-unit measure analysis files;
    - multiplying the per unit estimates by the number of estimated units in the region; and,
    - applying additional factors for annual achievability (ramp rates) and total overall achievability.

  The result of these calculations is a final estimate of total achievable conservation potential.
- **All-Sector Aggregator File**: This file extracts all the relevant data from the sector potential files, creating a single, annualized table of conservation potential. It also maps all conservation measures to various levelized cost and shape bins, as these are used downstream of this process, where measures are bundled by cost, shape, and modeling zone.

Supply Curve Analysis Flow

Figure H - 15 illustrates how the supply curve data and analysis flow from one file type to another, with the per-unit measure analyses flowing into the sector potential files, the sector files flowing into the aggregator file, and the aggregator file flowing into a set of Python scripts, which are used to bundle and transform the aggerated data into a final, hourly dataset for capital expansion modeling.

Figure H - 15: Supply Curve Analysis Flow

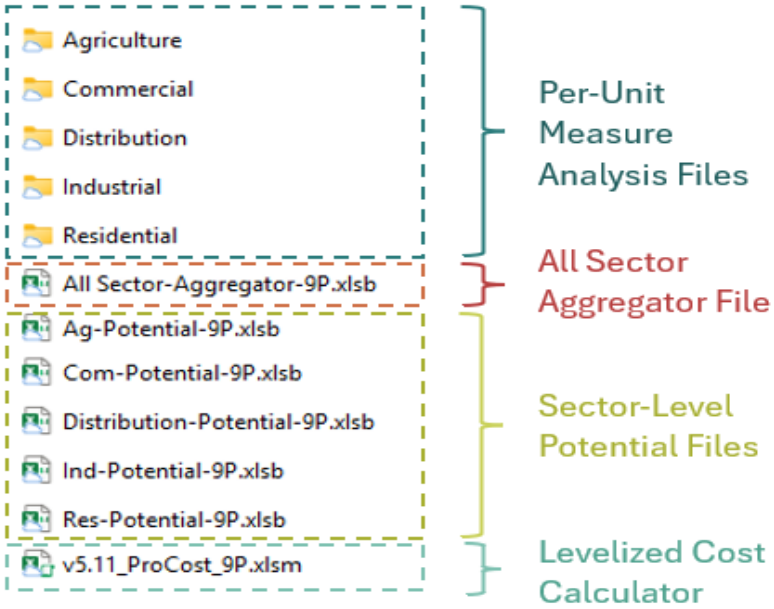


File and Folder Structure

The files and folders that make up the Ninth Plan supply curve materials are organized according to Figure H - 16. As there are many measure analysis files, they are organized within a folder named for each sector. The measure analysis files themselves are named according to the convention "[Sector]-[Measure Name]-9P". For example, the measure analysis file for residential clothes washers is named "Res-ClothesWashers-9P.xlsm".

At the same level as the measure analysis file folders are the sector-level potential files, which are named according to the convention "[Sector]-Potential-9P", and the all-sector aggregator file ("All Sector-Aggregator-9P"). Lastly, there is a file called "v5.11_ProCost_9P". This is the Council's conservation levelized cost calculator, ProCost, that uses inputs from the measure analysis files (for energy savings, costs, and lifetime) to calculate levelized costs for each measure.

Figure H - 16: Supply Curve File and Folder Structure



Where to Find More Information

For more information on these supply curve materials, please visit the Council's Ninth Plan website,[29] which contains a number of presentations, videos, and supporting materials for this work. You can also visit the Council's Conservation Resources Advisory Committee website,[30] which also contains presentations and discussions that helped guide and shape this work.

[29] https://www.nwcouncil.org/energy/ninthpowerplan.
[30] https://www.nwcouncil.org/energy/energy-advisory-committees/conservation-resources-advisory-committee.

Technical Appendix I: Demand Response Methodology and Potential

Contents

Introduction to Demand Response 2
- Total Demand Response Potential 3

Developing Demand Response Supply Curves 5
- Demand Response Products 6
- Global Assumptions 7
- Potential and Cost by Modeling Zone 8
- Estimate Technical Potential 9
- Estimate Achievable Potential 11
- Impact Parameters 12

Calculate Net Levelized Cost 13
- Cost Parameters 14

Dispatch and Deployment Assumptions 17

Demand Response Products and Summaries 18
- Electric Vehicle Charging 19
- Water Heating 21
- Space Heating and Cooling 24
- Irrigation 27
- Batteries 28
- C&I Demand Curtailment 30
- Price-Based Demand Response 31
- Demand Voltage Regulation 33
- Demand Response Technologies Considered but Not Modeled 34

Modeling Demand Response Supply Curves 35
- Binning and Preparation for OptGen 35

Demand Response Interaction with Energy Efficiency 37
Adjusting for Load Futures and Scenarios 38
Total Demand Response Potential 40
Excel Workbooks and Tools 43
Input Assumptions 43
Modeling Steps 44
Where to Find More Information 45

Introduction to Demand Response

Demand response (DR) allows utilities to adjust electricity demand by consumers at specific times to help reduce the power demand on the system, either through direct adjustments or by encouraging consumers with rates. Unlike supply-side generating resources, demand response operates on the demand side by modifying how and when electricity is used. As such, it can serve as an alternative to constructing new generation resources.

The Ninth Power Plan is analyzing demand response products in the residential, commercial, industrial, and agricultural sectors, as well as the utility distribution system. These products include utility-controllable and price-responsive options across the sectors. Utility-controllable products can change the operation of end-use equipment to reduce peak. Price-responsive products allow end-use customers to choose how to modify their energy consumption based on a price signal from the utility. Table I - 1 includes the list of demand response products that are evaluated in the Ninth Plan listed by sector. More details regarding the demand response products are included later in this section.

To estimate the demand response resource for the Ninth Plan, the Council develops supply curves that cover a range of demand response products. Demand response supply curves provide comparisons with generating resources and other demand side resources like energy efficiency. These supply curves serve as inputs into the Council's resource optimization models, along with generating resource reference plants, load forecasts, market conditions, etc. The Council considers results from these models in developing a resource strategy for the region. This appendix details how demand response supply curves have been developed for the Ninth Plan.

Table I - 1: List of Demand Response Products in the Ninth Power Plan

Residential	Commercial	Industrial and Agriculture
AC Switch	AC Switch	Irrigation Control (Ag)
Heating Switch	Heating Switch	Demand Curtailment (Ind)
Bring-your-own-thermostat	Bring-your-own-thermostat	Real Time Pricing (Ind)
Water Heater Control	Demand Curtailment	Critical Peak Pricing (Ind)

Residential	Commercial	Industrial and Agriculture
Critical Peak Pricing	Critical Peak Pricing	Demand Voltage Regulation (All)
Time-of-Use	Electric Vehicle Time-of-Use	
Electric Vehicle Charging Control	Demand Voltage Regulation	
Electric Vehicle Time-of-Use		
Demand Voltage Regulation		
Battery		

* Res = Residential; Com = Commercial, Ind = Industrial, Ag=Agricultural

Total Demand Response Potential

The aggregate demand response potential presented in the Ninth Power Plan reflects the combined contribution of a diverse portfolio of residential, commercial, industrial, and agricultural demand response products evaluated over the 20-year planning horizon. These products vary widely in technology type, customer participation model, seasonal availability, and cost. The Council assesses on a consistent basis so that their impacts can be directly compared with supply-side generating resources and energy efficiency measures. The resulting estimates represent the achievable level of peak load reduction that could be realized through utility programs, accounting for realistic participation rates, program performance, and operational constraints. Within this framework, achievable potential is defined as the amount of demand reduction that is expected to be reliably available to the power system under programmatic deployment.

Using these assumptions, the Ninth Power Plan estimates that total achievable demand response potential reaches approximately 6,636 megawatts in the summer period and 5,756 megawatts in the winter period by the end of the 20-year planning horizon. These totals represent the cumulative contribution of all modeled demand response products at their highest seasonal availability and form the basis for the demand response supply curves used in the Council's optimization modeling.

The supply curve for the demand response potential is provided in Figure I - 1 below. The figure represents the net levelized cost (in 2024 dollars) of each product, with the least cost products at the bottom of the chart and costs increasing from the bottom up. For products that operate in both the summer and winter the highest seasonal potential is represented. The incremental potential for a given product is illustrated in red, while the cumulative potential of all lower cost products is shown in blue. Table I - 2 provides the full product names corresponding to the abbreviations used in the figure.

Figure I - 1: 2046 Achievable Demand Response Potential with Net Levelized Cost - Combined

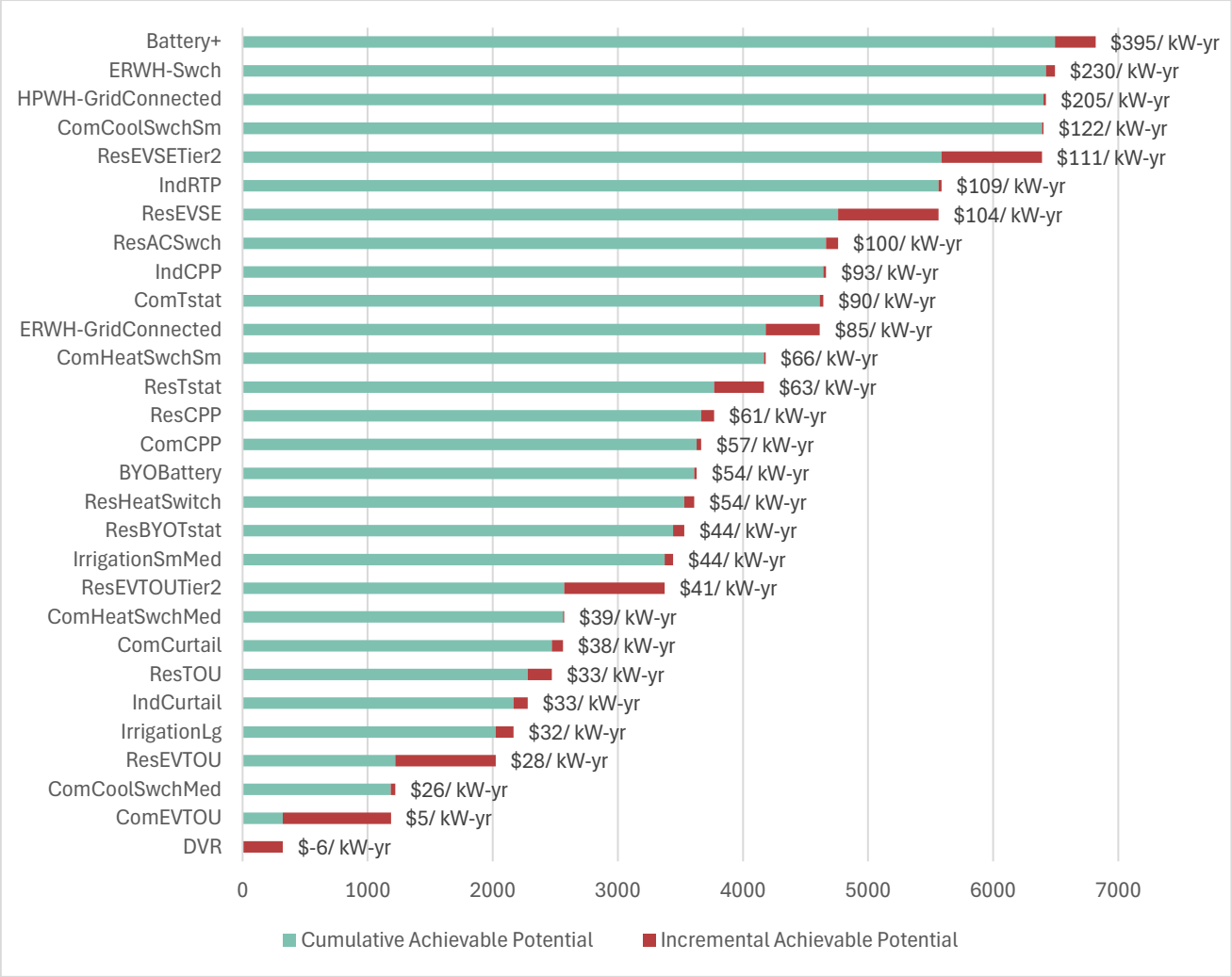


Table I - 2: Demand Response Products and their Abbreviations

Abbreviation	Full Name
DVR	Demand Voltage Regulation
ResBYOTstat	Residential Bring-Your-Own Thermostat
ResTOU	Residential Time-of-Use
ComCurtail	Commercial Curtailment
IndCurtail	Industrial Curtailment
ResCPP	Residential Critical Peak Pricing
ComCoolSwitchSm	Small Commercial Building Cooling Control Switch
EVTOU	Electric Vehicle Time-of-Use
ResTstat	Residential Thermostat

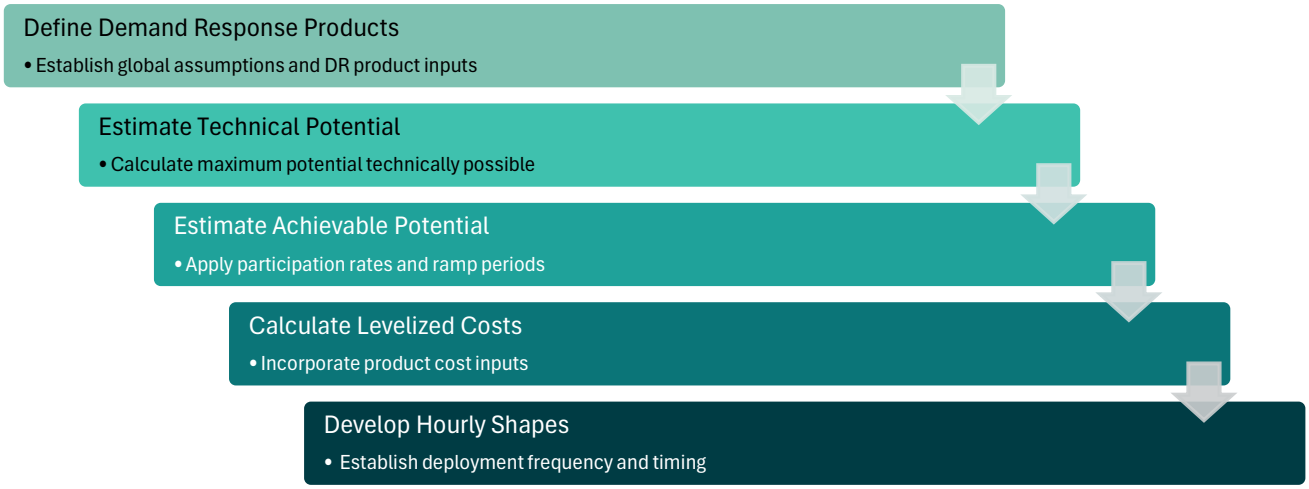
Abbreviation	Full Name
BYOBattery	Bring Your Own Battery
IrrigationLg	Irrigation Control for Farms
ComTstat	Commercial Building Thermostat
ComHeatSwitchMed	Medium Commercial Building Heating Control Switch
ERWH-GridConnected	Electric Resistance Water Heater Connected to the Grid
ResHeatSwitch	Residential Heating Control Switch
IndRTP	Real Time Pricing for the Industrial Sector
ResACSwitch	Residential Air Conditioning Switch
ComCoolSwitchMed	Medium Commercial Building Cooling Switch
HPWH-GridConnected	Heat Pump Water Heater Connected to the Grid
ERWH-Switch	Electric Resistance Water Heater Switch
Battery+	Battery Storage Purchased for Demand Response

Developing Demand Response Supply Curves

Council staff worked with the Demand Response Advisory Committee (DRAC) to determine the cost and impact input parameters for each demand response product. In addition, the product eligibility was largely based on external data sources such as: the residential building stock assessment (RBSA),[1] the commercial building stock assessment (CBSA),[2] and the Regional Technical Forum (RTF) work products.[3] Where appropriate, assumptions are consistent between the demand response and energy efficiency supply curves.

[1] 2022 Residential Building Stock Assessment: https://neea.org/residential-building-stock-assessment.
[2] Commercial Building Stock Assessment: https://neea.org/commercial-building-stock-assessment.
[3] RTF Demand Response Technologies: https://rtf.nwcouncil.org/demand-responses.

Figure I - 2: Demand Response Product Development Workflow



Demand Response Products

A demand response product is a resource that modifies electricity demand during a defined event. Demand response products in the Ninth Plan carry a bundle of characteristics that define their cost, impact, capabilities, and the end-use loads that it can impact. Products are proxy resources and are meant to best describe a representative demand response program structure rather than specific utility implementation. Demand response programs developed by different utilities using the same technology can vary significantly in costs, deployment strategies, and use cases. Variations in inputs and available load geographically within the region are captured when appropriate. Certain demand response products may be available in the summer, winter, or bi-seasonal, as listed in Table I - 3. The impact, cost, and deployment assumptions that define each demand response product are discussed further in this appendix.

Table I - 3: Demand Response Products by Season

Both Seasons	Summer Only	Winter Only
Smart Thermostat	AC Switch	Heat Switch
Water Heater Control	Irrigation	
Electric Vehicle Charging		
Curtailment		
Critical Peak Pricing		
Time-of-Use		
Real Time Pricing		
Demand Voltage Regulation		
Battery		

Global Assumptions

To calculate the demand response achievable technical potential, there are several key input parameters needed: global assumptions (economic and system) and product inputs (impact and cost). The global assumptions are listed in

Table I - 4 and the product inputs are listed in Table I - 6. Global assumptions are key data points that are applicable across the demand response products assessed and define the system and cost landscape that is used to estimate demand response potential and cost. System assumptions are discussed below while economic assumptions are discussed in the section on net levelized costs.

Table I - 4: Global Assumptions

Economic	System
Planning Horizon	Peak Definition
Discount Rate	Hourly System Load Profile
Inflation	System Sales Forecast
	Sector, Segment, End Use Shares
	Line Losses

Peak Definition

Peak definition is used to determine peak coincidence factors for demand response products as well as to develop hourly demand response deployment shapes. For peak coincidence analysis, peak is allowed to be any hour in the summer (June, July, August) or winter (December, January, February). Event time is limited to 4 hours and maximum hours per season is 40. This allows the potential assessment model to determine peak events throughout the year based on the system load shape and calculate coincidence factors for different end use loads that are impacted by demand response products. To develop hourly deployment shapes, peak is defined as 7-10 am and 5-9 pm in the winter and 6-10 pm in the summer. Actual deployment profiles may vary in duration than these based on the characteristics of the demand response product.

System Demand Forecast and Hourly Load Profile

The system demand forecast establishes baseline electricity sales in MWh by sector. Load is further disaggregated by segment and end-use shares when possible, to parse out load at the end use level. The disaggregated demand forecast is an important input to the demand response model as it serves as the starting point for the load that can be potentially impacted by demand response products. For more information on the load forecast see Technical Appendix F – Electricity Demand Forecast.

While most disaggregation of energy demand was developed in the load forecast, defining agricultural sales required further work as it was built into the industrial forecast. Data from the 2023 USDA

Census of Agricultural Irrigation and Water Management Survey[4] were used to approximate agricultural load by balancing authority. Using a conversion of 0.8 kW per pump horsepower (HP), total pump HP was converted to total MWh, which was then expressed as a percentage of the industrial demand forecast.

An hourly system load profile was developed using the regional hourly demand forecast and normalized to an 8,760-hour annual load shape. This provides the temporal framework for estimating peak coincidence factors.

Line Losses

The transmission and distribution power lines incur losses when transmitting electricity from one location to another. These losses need to be accounted for when estimating the difference in savings at the end-use site versus the utility busbar. For the Ninth Plan, the Council conducted research[5] and collected data from utilities and the Energy Information Administration (EIA) to determine the average losses on both the distribution and transmission systems. These values were found to be 4.4 percent for the distribution system and 2.8 percent for the transmission system.[6]

Potential and Cost by Modeling Zone

Previous power plans estimated demand response potential for the region as a whole. While this represents a picture of the region's overall demand response availability, it cannot represent potential differences in the types of demand response available on a sub-regional level or potential differences in the value of demand response on a sub-regional level. For example, some sub-regions of the Council's overall planning region may be willing to pay higher prices for demand response, given the unique characteristics and constraints of their sub-region.

For the first time, the Ninth Plan estimated demand response potential and cost for a set of seventeen smaller sub-regions or "modeling zones". The modeling zones, summarized in Table I - 5, correspond approximately to Northwest balancing authorities, or portions of balancing authorities. However, their main purpose is to reflect where different types and magnitudes of demand response are distributed across the region, as well as the differing costs that may be represented. In addition to allocating electric loads, customers, and equipment stocks across zones, other zone-specific adjustments are described later in this section for each demand response end use.

[4] 2023 USDA Census of Agricultural Irrigation and Water Management Survey: https://www.nass.usda.gov/Publications/AgCensus/2022/Online_Resources/Farm_and_Ranch_Irrigation_Survey.
[5] Research findings presented to the Council's Conservation Resources Advisory Committee available here: https://nwcouncil.box.com/s/opdoxu8ullwi3o0uedeodavgekid2ttt.
[6] More information on line losses can be found in Technical Appendix A – Global Assumptions.

Table I - 5: Modeling Zones

Modeling Zone Name	Modeling Zone Abbreviation
Avista Utilities	AVA
Bonneville Power Administration, Idaho and Montana	BPA_IDMT
Bonneville Power Administration, Oregon	BPA_OR
Bonneville Power Administration, Washington	BPA_WA
Chelan County PUD	CCPUD
Douglas County PUD	DCPUD
Grant County PUD	GCPUD
Idaho Power Company	IPCO
NorthWestern Energy	NWMT
PacifiCorp, East	PACE
PacifiCorp, West	PACW
Portland General Electric	PGE
Puget Sound Energy, Central	PSE_Central
Puget Sound Energy, North	PSE_North
Puget Sound Energy, Olympia	PSE_Olympia
Seattle City Light	SCL
Tacoma Power	TPWER

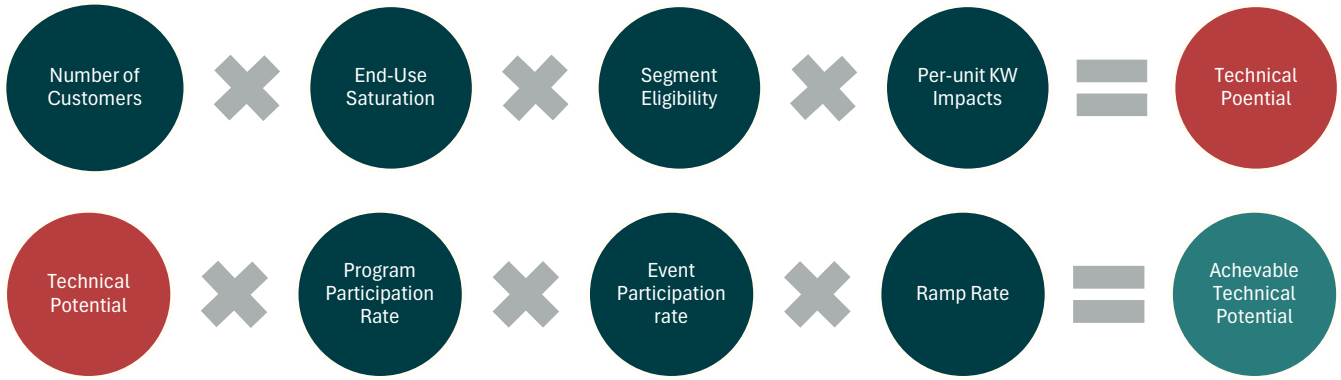
Estimate Technical Potential

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of demand response product, technical potential is typically estimated using either a bottom-up or top-down method.

Bottom-Up Methodology

The bottom-up method (Figure I - 3) is used to assess potential for demand response products that affect a piece of equipment in a specific end use. This method is therefore applicable to demand response products such as direct control of space and water-heating equipment or smart thermostats. In the bottom-up method, technical potential is determined primarily as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kW) peak load impact. The bottom-up method is intended to simplify the estimation potential for equipment-based products.

Figure I - 3: Illustration of Bottom-Up Methodology to Estimate Potential



Top-Down Methodology

The top-down method (Figure I - 4) estimates technical potential as a fraction of the participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use, then estimates technical potential as a fraction of the end-use loads. Total potential is then estimated by aggregating the predicted load reductions of the applicable end uses. The top-down estimation method is applied to demand response products that target the entire facility or load (rather than specific equipment), such as commercial and industrial demand curtailment, time-varying rates, or programs offered to entire sectors, such as to the irrigated agriculture sector.

Figure I - 4: Illustration of Top-Down Methodology to Estimate Potential

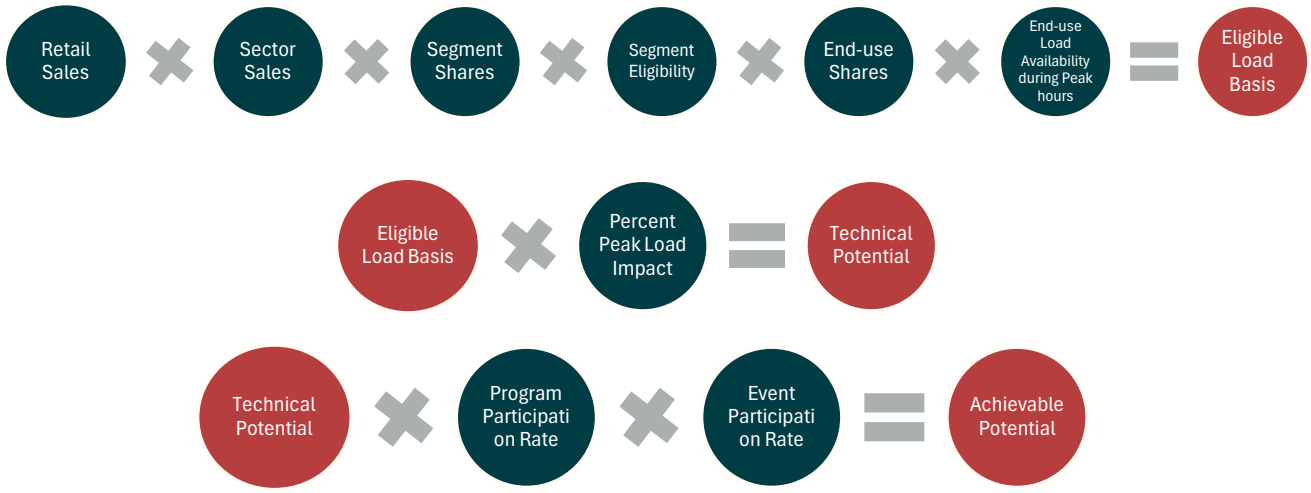


Table I - 6: Demand Response Products Listed by Assessment Methodology

Bottom-Up	Top-Down
AC Switch (Res and Com)	Irrigation Control (Ag)
Heating Switch (Res and Com)	Demand Curtailment (Com and Ind)
Bring-your-own-thermostat (Res and Com)	Real Time Pricing (Ind)
Water Heater Control (Res)	Critical Peak Pricing (Res and Com)
Battery (Res)	Time-of-Use (Res)
	Demand Voltage Regulation (All)
	Electric Vehicle Charging (Res and Com)

Res = Residential, Com = Commercial, Ind = Industrial, Ag=Agricultural

Estimate Achievable Potential

Achievable potential reflects a subset of technically feasible demand response opportunities that are assumed to be reasonably obtainable, based on market conditions and the end-use customers' ability and willingness to participate in the demand response market. There are two components for estimating achievable potential: market acceptance (or participation) and the ramp rate. Participation is also broken down into program participation (the likelihood of eligible population enrolling in a demand response program) and event participation (the probability that customers participating in a program will respond to a demand response event), an important consideration in voluntary demand response programs.

Ramp rates indicate the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of demand response product and the stage in the product's life cycle. Ramp rates indicate how quickly the maximum achievable potential may be reached, but they do not affect the amount of maximum achievable potential.

A full list of potential and cost inputs as well as eligibility calculations for each DR product can be found on in the demand response supply curve workbooks listed on the Council's Ninth Plan website.[7]

[7] https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements. Direct link to demand response supply curve workbooks is available here: https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.

Table I - 7: Demand Response Product Assumptions

Impact Assumption	Cost Assumptions
Eligibility	Setup Cost
Peak Load Impact	Operations and Maintenance Cost
Program Participation	Marketing Cost
Event Participation	Equipment Cost
Ramp Rates	Value of Lost Service
Attrition	

Impact Parameters

Estimating demand response potential depends on clearly defining which customer sectors, segments, and end-uses are eligible to participate. This determines the total load available for potential reduction. Within this framework, several key parameters shape the final estimates. Product parameter inputs are based on a review of existing program impact evaluation studies and technology performance characteristics, along with input and review from the Demand Response Advisory Committee.

Eligibility

The potential for demand response is a function of the customer sectors, segments, and end uses that the demand response product effects. Defining these eligible classes narrows down the potential load or population that can be part of a demand response product. Equipment stock saturation forecasts and advanced metering infrastructure (AMI) deployment are often used as well to define customer eligibility. When notable, specific methods for determining eligibility for certain demand response products are described in the Demand Response Products and Summaries section of this appendix.

Peak Load Impact

Peak load impact estimates the expected demand reduction when a demand response product is deployed. For bottom-up demand response products, this is defined as a kW per participant value, usually reflecting the load reduction expected for each individual piece of equipment enrolled in the program. This value is used as the basis to estimate technical potential along with population, equipment stock saturations, and eligibility. For top-down demand response products, peak load impact is defined as the percent of the eligible load basis that is reduced during a peak event. The actual level of load impact may differ from event to event depending on when it is called, or even between hours of a given event. To the extent that this was reliably quantifiable it is reflected in the hourly shape profiles of the demand response products.

Program Participation

Program participation represents the fraction of the eligible population or load expected to enroll in a fully deployed demand response program. Participation assumptions are deliberately conservative estimates to account for potential cannibalization between different demand response products. For example, certain products may impact the same end use, such as a residential time of use rate and a smart thermostat program both potentially impacting space heating and cooling. While it is prohibitively difficult to model interaction between these products should they both be selected in a portfolio, being conservative on participation rate assumptions minimizes any double counting of potential capacity.

Event Participation

Event participation captures the share of enrolled customers expected to respond to a dispatch call during an event. This can reflect load switch failure, connectivity issues, and participant opt-outs and overrides. For bottom-up demand response products the coincidence of the impacted end uses energy usage with the time of the demand response call may be incorporated in the event participation. For top-down demand response products, this is already embedded within the estimated coincidence factors derived from load-shape analysis.

Ramp Rates

A program ramp rate is included for each demand response product to reflect the number of years it may take to reach full participation. For example, for the AC Switch product, the full participation rate is 10 percent, but the assumption is that it will take five years to reach that level. Due to evidence that much of the enrollment in programs occurs in the first year of availability, participation begins at 50% of its final assumed rate and increases linearly over its ramp period – so 5 percent of the population in year one, 6 percent in year two, up towards 10 percent in year five and beyond. All products assumed five-year ramps.

Calculate Net Levelized Cost

In addition to the total impact that could be achieved, by year, for a given product, the supply curves also include an estimate of what it would cost, on a per-kilowatt-year basis, to acquire these impacts. Consistent with all cost assumptions in the Ninth Plan, all costs are in 2024 dollars. To fairly compare all resources in the resource strategy analysis, these costs are expressed as a net levelized cost of the capacity resources provided. Net levelized costs are measured as the discounted life-cycle $/kW-year cost of deploying a demand response product, which accounts for both positive and negative costs (e.g. benefits), and are calculated as the net present value (NPV) of the product costs divided by the NPV of the energy impact of the product. For demand response, the only benefit (negative cost) included is the value of demand response to defer transmission and distribution investment (T&D deferral). In the Ninth Plan, T&D deferral is estimated to be about $30.85 per kilowatt-year, where $11.13 is from transmission deferral and $19.71 from the distribution system. These values are based on input from regional utilities. See Technical Appendix A – Global Assumptions for more information.

Net levelized costs are based on the total resource cost perspective which includes all known and quantifiable costs related to demand response products and programs. The calculation of each demand response product's levelized cost accounts for the relevant direct costs of a demand response product, including setup costs, operations and maintenance costs, equipment costs, marketing costs, and value of lost service. These, along with the T&D deferral, are the components of the net costs, which are then levelized to 2024 dollars using a 3.7 percent discount rate.[8] Notably, not all cost categories apply to every demand response product. For example, a bring-your-own thermostat program will not have any equipment cost as it is assumed the customer already owns the thermostat. Additionally, net levelized costs for products may vary across modeling zones due to zone size, total potential, or differing cost assumptions between zones. Illustrated in this appendix are weighted average costs of each product across the different modeling zones.

Finally, net levelized cost for each product is calculated with assumptions based on summer and winter impacts. Impact assumptions for each season may differ, impacting the assessed cost and potential for the product for each season. Since it is assumed that each dual season product will be deployed for both seasons, however, the net levelized cost ultimately used for the product is that for the season with the greatest amount of assessed potential.

Cost Parameters

Setup Cost

The setup cost is a one-time cost experienced by a utility to initiate a new demand response program. This was roughly estimated at $175,000.[9] There are many factors that may go into the actual cost a utility may experience to start up a new demand response program that could make it vary widely from this amount. A utility with no demand response experience or infrastructure starting up their first demand response program will likely experience significantly different costs than a utility that has already developed several programs. This setup cost was chosen as a proxy to represent the costs unique to developing a single demand response program irrespective of the existing demand response infrastructure. For modeling zones that align with one geographic section of a given utility (e.g. PSE North) the setup cost is split between the number of modeling zones that make up that utility.

In accordance with feedback from the Demand Response Advisory Committee, this value was increased to $500,000 only for price-based demand response products like TOU and CPP. This reflects the significant cost experienced by utilities to implement new billing systems to accommodate these types of rates.

The one-time nature of this cost means that it has differing magnitudes of impacts on the levelized cost depending on both the size of the modeling zone as well as the size of the potential for the given demand response product. For larger modeling zones with greater load and thus, often, greater

[8] See Technical Appendix A – Global Assumptions for more information.
[9] Based on professional judgement and discussion with the Demand Response Advisory Committee.

potential, the impact of the setup cost on the levelized cost is diluted, as other costs scale up with the size of the potential while the setup cost does not. For smaller modeling zones and smaller products, the setup cost represents a larger share of the levelized cost. Utilities in these smaller modeling zones are also less likely to already have demand response enabling infrastructure like advanced billing systems and are more likely to experience this higher cost as well as have it impact the levelized cost.

Operations and Maintenance Cost

Operations and maintenance (O&M) costs reflect the ongoing cost experienced on an annual basis for keeping a demand response program in operation, usually including the cost of distributed energy resource management systems (DERMS). There are several different ways that demand response programs can be operated, whether that be in house or through a third-party vendor. The structure of those costs can be different from program to program. Further, there can be other unique ongoing costs like the cellular fee required for communication with a load control device. This proxy cost summarizes the best available data for the demand response products assessed. For direct load control demand response products, this cost is expressed in dollars per kW per year. For price-based demand response products it is expressed in dollars per year, with the cost being half the estimated cost of one full time employee ($87,500).

Marketing Cost

Marketing costs reflects the cost of recruiting each new participant into the demand response program. Costs are mostly standardized but may be different to reflect the challenge of spreading awareness of a program to potential participants. In this sense, it is somewhat connected to incentives in that it reflects the cost to get a customer willing to participate in the program. Marketing cost is expressed on a dollar per new participant basis.

Equipment Cost

Equipment cost reflects the incremental cost required to enable an end-use to respond to a demand response event. This can be the cost of a load switch device, which has traditionally been used in demand response programs, or any other additional equipment needed to enable device communication. This is expressed on a dollar per new participant basis. Unique examples of equipment costs are discussed in the individual sections for each demand response product/end use.

Portion of Incentive Impacting Levelized Cost/Value of Lost Service

Value of lost service represents the loss of utility experienced by a customer from participation in a demand response program. This value is derived as a percentage of incentive cost, with the idea being that the incentive cost is the maximum amount of cost a participant would be willing to incur in the form of lost utility. If the value of lost service were greater than the incentive value the participant is receiving, then they would not participate in the program. The value of lost service is estimated as a percentage of the assumed incentive, with the percentage being based on sector: 75% for industrial,

55% for commercial, and 25% for residential, reflecting the fact that interrupting service is often more disruptive for industrial/commercial customers than it is for residential (see Table I - 8).[10]

Additionally, the value of lost service for demand response products that are assumed to be frequently deployable is reduced to just 10% of the incentive value. These demand response products are assumed to be frequently deployable because the design of the program should be such that the impact on the participant is nearly negligible, and thus there does not need to be a limitation on the number of instances per season that it can be deployed. The lack of impact on the participants suggests that a lower value of lost service should be utilized.

Incentives

Incentives are collected as a basis for calculation of the values of lost service in the form of an annual incentive (dollar per participant per year) and/or a one-time incentive (dollar per participant). A variety of different structures can be used in utility demand response programs, including a performance-based incentive (dollar per kWh or event participated), but this analysis is limited to annual and one-time incentives. While used as a guide for the value of lost service calculations and captured in connection with expected participation rates, incentives are not included as an explicit cost in the net levelized cost calculation. The Ninth Plan uses a regional total resource cost test, which sees incentive payments as both a cost to the utility and a benefit to the participants, and thus not a cost to the region.[11]

Table I - 8: Share of Incentive Included as a Cost

Sector	Percent of Incentive in Levelized Cost
Frequently Deployable	10%
Residential	35%
Commercial	55%
Industrial	75%
Agricultural	75%

Transmission and Distribution Deferral

There are certain resources that can defer investment in transmission and/or distribution systems (T&D), including demand response. The value associated with deferring these investments is attributed to resources that have the capability to do so. The T&D deferral credit for zones west of the

[10] These values are based on the California PUC Demand Response Cost Effectiveness Protocol: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness.

[11] This approach is consistent with the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources: https://building-performance.org/education/resources/nesp-national-standard-practice-manual-nspm.

cascades is $38.87/kW-yr, while the T&D deferral credit for zones east of the cascades is $16.48/kW-yr. The BPA Oregon and Washington zones, that cover areas both east and west of the cascades, have a regional T&D deferral credit of $30.85, where $11.13 is from transmission deferral and $19.71 from distribution deferral. These values are based on input from regional utilities. See Technical Appendix A – Global Assumptions for more information.

T&D peak is defined as hours ending 8 and 9 am and hours ending 6 and 7 pm for winter-peaking zones (December, January, and February) and hours ending 5 through 8 pm for summer-peaking zones (July and August). The amount of this credit value that demand response products are attributed is dependent on the deployment shape and capabilities of each product and how they align with those peaks.

Frequently deployed demand response programs (like EV time-of-use charging) are modeled with a fixed shape deployment in the Ninth Plan. To determine the T&D deferral value from these resources the hourly shape is assessed against the hours of highest load in the demand forecast.[12] If the demand response program provides full value in these hours, it receives the full T&D deferral credit. If the program effectiveness is lower in these hours, the T&D deferral credit is reduced.

Limited deployment demand response products receive only half of the calculated T&D deferral credit. This is because, while they are deployed specifically for peak events, there may be instances where T&D peak occurs over multiple consecutive days. Many demand response programs have limitations on how many times per week load reduction can be called, or customers may be more likely to opt out if load reduction is called for too frequently. Additionally, utilities may run into their seasonal deployment limitation (15 events per season) before T&D peak is realized, creating some unpredictability as to how confidently limited deployment demand response can successfully defer transmission and distribution upgrades. The 50% T&D deferral credit is a proxy to represent this constrained deferral value.

Dispatch and Deployment Assumptions

Demand response has traditionally been limited to being deployed a handful of times per season during peak hours when the grid is strained. This is often still the case, but as demand response technologies have evolved, demand response programs have evolved as well. The hourly nature of resource modeling for this plan allows the Council to represent the dispatch and deployment of different demand response products with more granularity. The Ninth Plan distinguished between limited and frequent dispatch categories to capture this difference.

[12] Hours ending 8, 9, 18, and 19 were assessed in the winter, hours ending 17 through 20 in the summer. Actual peak hours can vary based on load forecast and weather pattern.

Limited Dispatch

Demand response products that are designated as limited dispatch products may be deployed up to 15 times per season that they are available. Their dispatch is limited because the curtailment is significantly disruptive such that customers would likely be unwilling to participate in the program if curtailment were requested more than 15 times per season. These products target the seasonal peak events when the grid is most strained.

Frequent Dispatch

Demand response products that are designated as frequent dispatch have the flexibility to be deployed for more than just the handful of seasonal peaks throughout the year. These products can be used for price mitigation, shifting loads from times of high energy cost to low energy cost, as well as targeting peak events when the grid is strained. Because these products can be deployed frequently throughout the winter and/or summer seasons, they are treated with a fixed shape similar to conservation.

Table I - 9: Demand Response Products Listed by Deployment Type

Limited	Frequent
Space Heating and Cooling (Res and Com)	Electric Vehicle Charging (Res and Com)
Irrigation Control (Ag)	Water Heating (Res)
BYO Battery (Res)	Time-of-Use (Res)
Demand Curtailment (Com and Ind)	Battery Plus (Res)
Critical Peak Pricing (Res and Com)	Demand Voltage Regulation (All)
Real Time Pricing (Ind)	

Demand Response Products and Summaries

This section describes the demand response products evaluated in the Ninth Power Plan. Each product represents a distinct method for reducing or shifting electricity consumption during periods of high system demand. The summaries below highlight how these products function, their eligibility criteria, net levelized costs for the region, and estimated potential by 2046. The input assumptions informing the total potential and cost for each product are developed through a combination of demand response program evaluations, utility potential assessments, and DRAC professional judgment. Unless otherwise noted, assumptions listed in these sections are based on professional judgment.[13] Each summary also has a figure illustrating a 24-hour deployment shape for the product.

[13] See "DR_Database" workbook in the Inputs folder for full list of input assumptions for all demand response products available here: https://nwcouncil.box.com/v/ninthplanDRsupplycurves.

These deployment shapes are set for the winter season to show how they may also address the winter morning peak when needed.[14]

Electric Vehicle Charging

Electric vehicle charging is one of the fastest growing loads in the region and also one of the most flexible. Presently, most EV charging at the residential level occurs in the early evening hours as drivers return home – typically aligning with evening peak hours. However, the charging does not need to be performed during those hours, so long as the vehicle is charged to the expected level when the user wishes to drive again, usually the following morning. If the correct signal is given, charging load can be shifted away from evening peak hours to hours of lesser need. This can be done either actively through direct control of the charging load or passively through price signals that encourage customers to shift their charging behaviors. Separate demand response products are modeled for these methods, but all are attributed an equipment cost of $60 representing the incremental cost of charger Wi-Fi enablement. Participation for residential EV charging demand response products is assumed at 40% of eligible load and split to 20% each between active managed charging and EV time of use.

When done correctly, EV charging demand response should not impact the program participant as their vehicle should be charged appropriately in the morning regardless of whether it started charging in an unmanaged scenario versus under a managed program. EV charging demand response is thus treated as frequently deployable. Additionally, it is assumed that managed charging demand response events can last for six hours rather than four since it does not matter to the participant when or how long the vehicle is charged, so long as it is charged in the morning. The Council's internal electric vehicle forecast is used to generate customer count and available charging load.[15]

Active Managed EV Charging (EVSE)

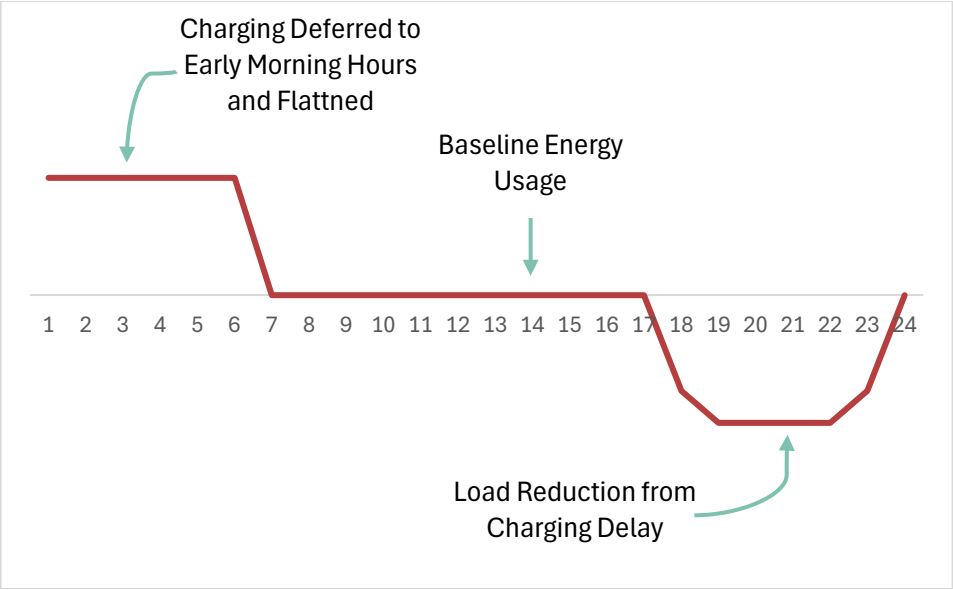
The active managed charging demand response product shifts EV charging times to off-peak hours through WiFi-enabled charger controls or vehicle telematics. The operating utility dispatches a signal to the charger or the vehicle telematics system to delay charging until a certain time in the evening. Under the active managed charging product, the utility provides incentives to the customer in exchange for the ability to shift their charging time. The operator of an active managed charging program can stagger the times in which charging returns for different vehicles or adjust the throttle level of the charger. This flattens and extends the return charging load, such that all the chargers do not begin charging simultaneously, avoiding creating a new local peak and potential subsequent transformer upgrade costs. It is also a more reliable and predictable form of load reduction because

[14] Deployment shapes for DR products that are only available in the summer such as Irrigation and AC Switch are set for summer deployment.
[15] See Technical Appendix F – Electricity Demand Forecast.

the utility has direct control rather than relying on the customer to change their behavior with price signals.

Figure I - 5 and subsequent figures in this section show the shape assumed for the DR product. They assume the baseline energy usage, load reduction, and any shift in load or bounce back resulting from the event.

Figure I - 5: Active Managed EV Charging – 24 Hour Demand Response Deployment Shape

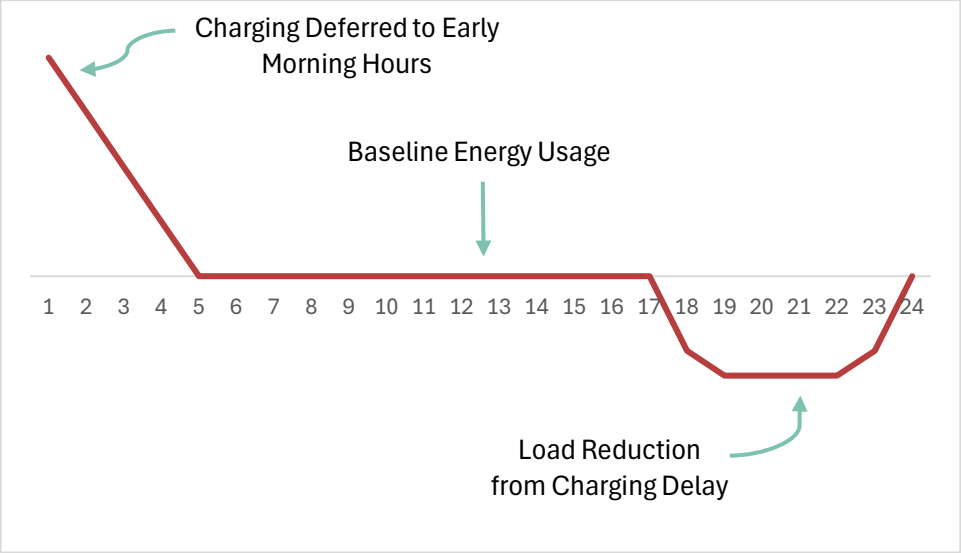


EV Time of Use

Time-varying rates targeted towards EV owners are designed to encourage drivers to shift charging to off-peak hours. The EV TOU product relies on participants to manually change their charging behavior, either through actively plugging the charger in when off peak rates begin or setting their charger to start charging at that time. Unlike the active managed charging demand response product, the utility does not have control or ability to stagger or flatten the returning charging load. The shape of the EV TOU product thus has a more pronounced immediate spike of returning load at the end of the demand response event times than the active managed charging product.

The EV TOU product relies on the customer's existing meter. TOU customers require advanced metering infrastructure (AMI) in order to participate, so eligibility for EV TOU was determined based on AMI saturation in each modeling zone. Residential and Commercial EV TOU products are separately modeled in this analysis, as the residential and commercial charging load forecasts are developed separately.

Figure I - 6: EV TOU – 24 Hour Demand Response Deployment Shape



Extra Tiers of EV Demand Response

Electric vehicle charging represents one of the largest sources of new load growth relative to the Council's previous plan. While a significant share of this load is expected to be subject to some form of managed charging in practice, the underlying load forecast assumes a fully unmanaged charging profile and therefore does not reflect the impacts of load flexibility. The purpose of this approach is to identify the cost-effective amount of charging for the region. To account for this disconnect, an additional tier of demand response potential was modeled for both active managed charging and EV time-of-use (TOU) programs, each assuming an incremental 20% increase in program participation. These additional tiers incorporate higher incentive levels – and corresponding values of lost service – to reflect the increased effort and cost required to achieve deeper levels of customer engagement and participation beyond the base program assumptions.

Table I - 10: EV Charging Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
EVSE	802	$104
ResEVTOU	802	$28
ComEVTOU	863	-$5

Water Heating

Electric tank water heaters can be readily integrated into demand response programs. Water heaters can use electricity to heat the water at times when the grid is less strained and energy is less expensive and then store the heat for hours until hot water is needed, acting as a thermal battery. This

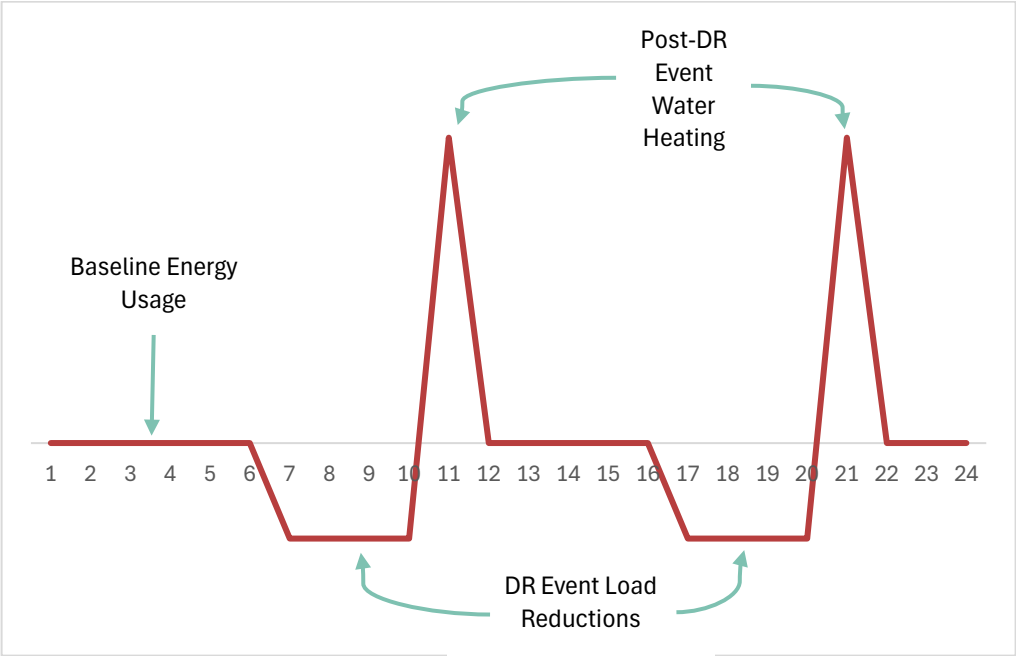
can be done by delaying the reheating of water during peak demand periods of scarce and expensive energy until the hot water in the tank gets below a certain level. It may also be done by preheating tank water in the hours leading up to peak periods, which allows the hot water to go longer before needing to be heated again. Water heating demand response products are assumed to be frequently deployable as they have been shown to have little to no effect on participant comfort. Water heaters are either able to ride out demand response events with the heated water in the tank or will automatically opt out of the event once there is insufficient hot water, which is reflected in event participation rates.

Electric Resistance Water Heating (ERWH)

Load Switch

Traditional water heater demand response programs in the region have relied on the installation of a load switch on the water heater. Under this demand response product, the water heater load is curtailed completely during the demand response event period unless the water falls below a certain temperature. The equipment cost for load switch water heating demand response is $300, reflecting the cost of the device and installation in line with the water heater. In Washington modeling zones, the equipment cost is $350 to reflect the state requirement that installation be performed by a licensed electrician.

Figure I - 7: Load Switch Water Heating - 24 Hour Demand Response Deployment Shape

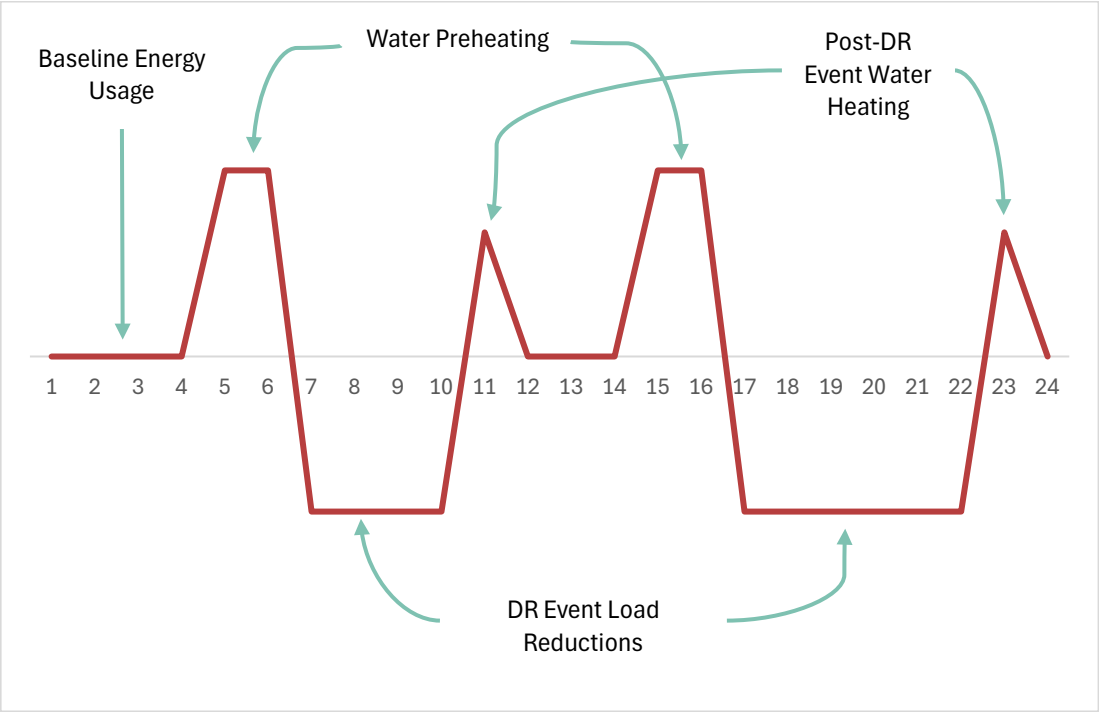


Grid-Connected

Technological advances have introduced a new method of interaction with water heaters. Grid interactive water heaters can have a communications module installed that gives demand response program operators more precise control over water heating loads. This can allow operators to preheat

storage tanks in advance of demand response events, allowing the water heater to ride out longer periods of load reduction. This also distributes much of the shifted load away from the bounce back hour immediately after the demand response event. It also allows this product to serve up to six-hour demand response events. The equipment cost assumption for the grid-connected product is $110. While there is not yet significant market deployment of the universal communications modules required by this product, this assumption relies on estimates of bulk order costs for a well-developed demand response program.

Figure I - 8: Grid Connected Water Heating – 24 Hour Demand Response Deployment Shape



Heat Pump Water Heating (HPWH)

Heat pump water heaters are modeled separately due to their higher efficiency and smaller available load for shifting. Early study results have shown that HPWHs can provide approximately half of the peak load impact per water heater relative to ERWHs. Nearly all HPWHs are installed with grid-interactive capabilities, so no switch-based product was developed for this class of water heater.

Eligibility for ERWH and HPWH programs was determined using residential stock forecasts developed by the load forecast team using RBSA data.[16] The analysis assumed that all new water heaters in Washington and Oregon would be grid-enabled water heaters in alignment with regulation mandating that new water heaters in these states be built with this capability through a CTA-2045 standard port.

[16] See Technical Appendix F – Electricity Demand Forecast.

The overall deployment shape for heat pump water heating is the same as that for grid-connected water heating.

Table I - 11: Water Heating Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ERWH-Switch	73	$230
ERWH-GridConnected	434	$85
HPWH-GridConnected	19	$205

Space Heating and Cooling

Space heating and cooling systems are a significant contributor to peak demand and therefore a prime target for demand response programs. These demand response products reduce load by adjusting indoor temperature settings or cycling equipment operation during events. Because comfort is typically affected, all HVAC-related programs are modeled as limited deployment resources that can be deployed a finite number of times per season. Further, these programs can only be deployed for 3 hours, as evaluations have shown that opt-outs increase significantly after this time.

Load Switch

Load switch programs directly curtail central AC or heating load through a load control switch installed on a customer's air conditioning or heating unit. This can curtail load entirely or cycle the cooling or heating load on and off for increments of time. There is no capability to preheat or precool in advance of the demand response event windows so all increase in demand occurs after the demand response event. Figure I - 9 shows the evening peak that is addressed in summer by the AC Switch product while Figure I - 10 shows the morning and evening peaks that can be addressed in winter by the Heat Switch product.

Figure I - 9: AC Switch – 24 Hour Demand Response Deployment Shape

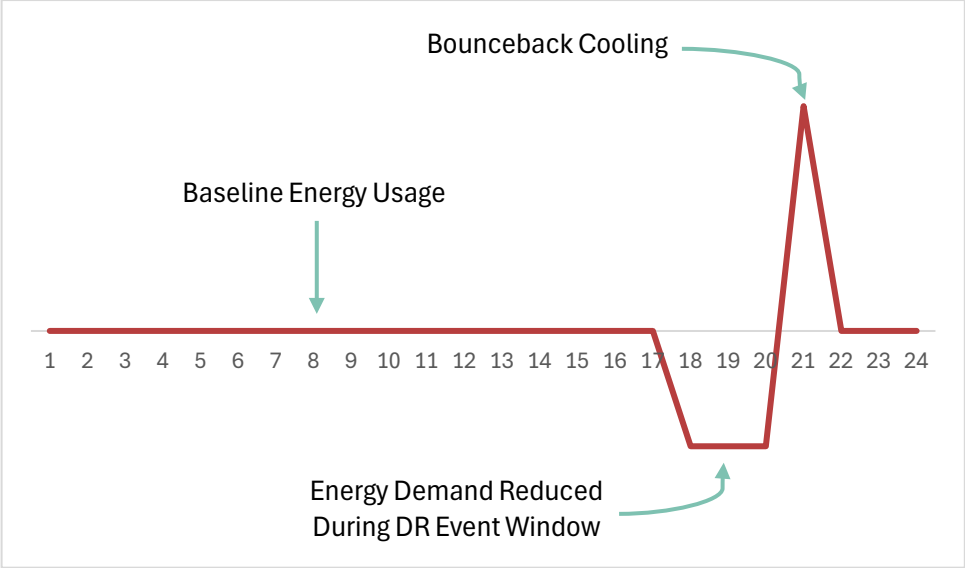
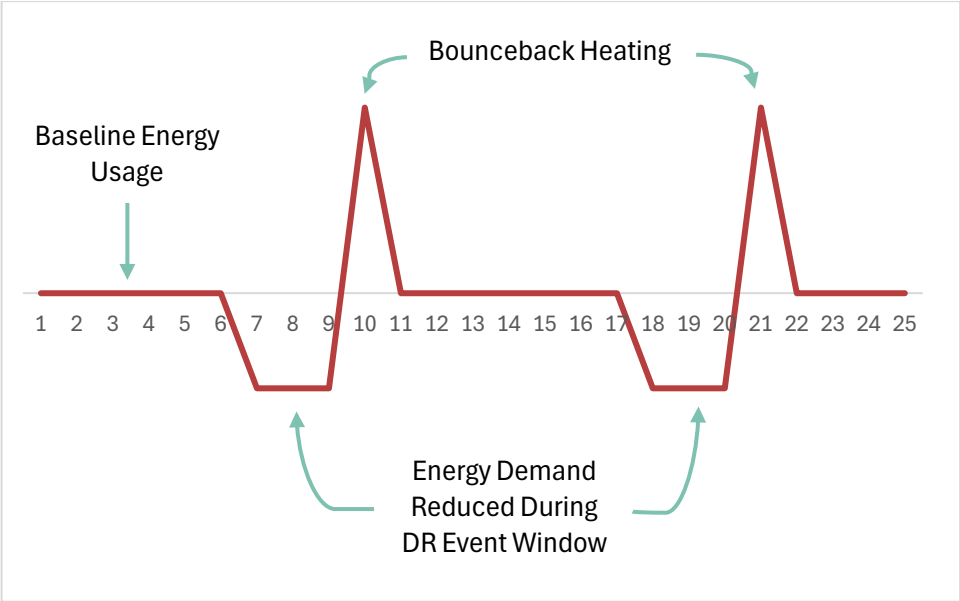


Figure I - 10: Heat Switch – 24 Hour Demand Response Deployment Shape



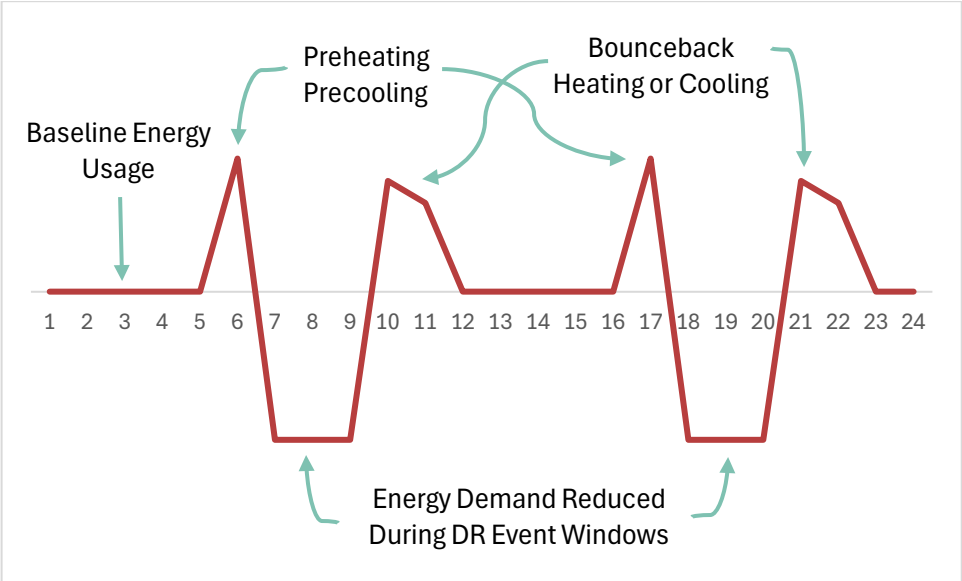
Smart Thermostat

Smart thermostat programs use WiFi-enabled thermostats to reduce load during demand response events. These programs automatically change the setpoint temperature on heating or cooling systems before a demand response event to preheat or precool in order to avoid loss of comfort. During the demand response event the thermostat is adjusted a few degrees to reduce heating and cooling energy demand. Residential and commercial smart thermostat products are modeled in the Ninth Plan.

- Bring Your Own Thermostat (BYOT): The BYOT product relies on existing smart thermostats that customers enroll in the program. Because the product relies on an existing smart thermostat there is no added equipment cost for the product.
- ResTstat: The ResTstat product assumes the procurement and installation of the smart thermostat by the utility and thus includes the $170 equipment cost of providing a smart thermostat to the customer to be used in the demand response program. This expands eligibility to all homes with central heating and cooling systems

Eligibility for space heating and cooling demand response products was determined through heating and cooling stock saturation forecasts developed from RBSA data.[17] Central electric heating and cooling equipment are eligible for these demand response products. Existing smart thermostat saturations to determine eligibility were taken from RBSA, and a modest annual growth rate of 3.6% was incorporated to model natural adoption. Eligibility for switch products and thermostat procurement are determined by the subset of customers with central electric heating or cooling that are outside of the start thermostat saturation.

Figure I - 11: Smart Thermostat – 24 Hour Demand Response Deployment Shape



[17] 2022 Residential Building Stock Assessment: https://neea.org/residential-building-stock-assessment.

Table I - 12: Space Heating and Cooling Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ResBYOT	98	$44
ResTstat	398	$54
ResACSwitch	96	$100
ResHeatSwitch	79	$48
ComACSwitchSm	14	$122
ComACSwitchMed	39	$26
ComHeatSwitchSm	15	$63
ComHeatSwitchMed	11	$33

Irrigation

Irrigation demand response curtails load from irrigation pumps during the summer months in response to a limited number of calls from the program operator. Customers can participate through automatic dispatch in which a shutoff signal is sent by the program operator or through manual dispatch where a customer manually shuts off their pumps when notified of a demand response event. The automatic dispatch option typically requires the installation of a load control switch on the irrigation pumps. The dispatch structure mirrors established irrigation programs in the region.[18] Groups of participants are given staggered dispatch times between 2 pm and 10 pm, with each group providing four hours of curtailment. It assumes that participants enroll 80 percent of their available irrigation load for curtailment, while peak coincidence is accounted for using the top-down evaluation method.

To reflect the differing costs and enrollment dynamics across the agricultural sector, two irrigation demand response products are modeled: one for large farms (more than 2,000 irrigated acres) and another for small to medium farms. USDA data from the 2024 Census of Agricultural Irrigation and Water Management Survey[19] for total acres irrigated and irrigated acres per farm was used to develop customer count for each product. The suitability of irrigation demand response varies significantly across the region due to factors such as dominant crop types, irrigation methods (e.g., well versus canal), and well depth, all of which influence both program and event participation. The Ninth Plan's increased geographic granularity allows these differences to be reflected to some extent, with each

[18] Idaho Power's Irrigation Peak Rewards program and Rocky Mountain Power's Irrigation Load Control Program helped guide the development of this DR product.
[19] 2024 Census of Agricultural Irrigation and Water Management Survey: https://www.nass.usda.gov/Publications/AgCensus/2022/Online_Resources/Farm_and_Ranch_Irrigation_Survey.

balancing authority's location east or west of the Cascades used as a distinguishing factor to adjust inputs where appropriate and illustrate regional variation.

Idaho Power has maintained an irrigation demand response program for over two decades. This program has been substantial and consistent enough that its impacts are likely being baked into the Council's irrigation load forecast. For this reason, 200 MW of capacity was removed from the Idaho Power zone's demand response potential.

Figure I - 12: Irrigation Control – 24 Hour Demand Response Deployment Shape

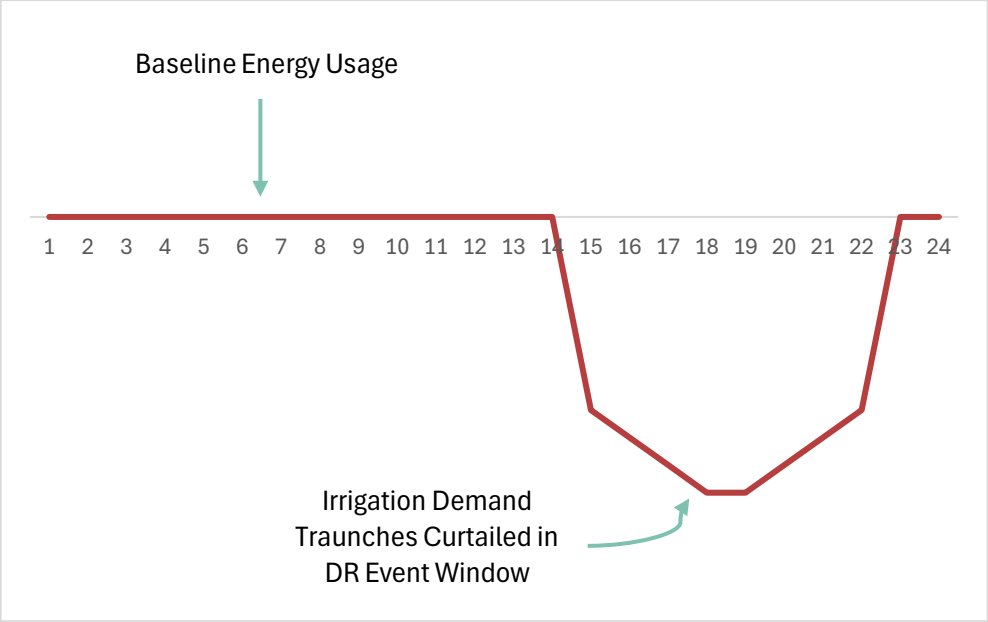


Table I - 13: Irrigation Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
IrrigationSmMed	69	$44
IrrigationLg	143	$32

Batteries

Home battery storage provides a flexible means of reducing peak load by discharging stored energy during high-demand hours in the evening. Two battery demand response product configurations are modeled.

Bring Your Own Battery (BYO Battery)

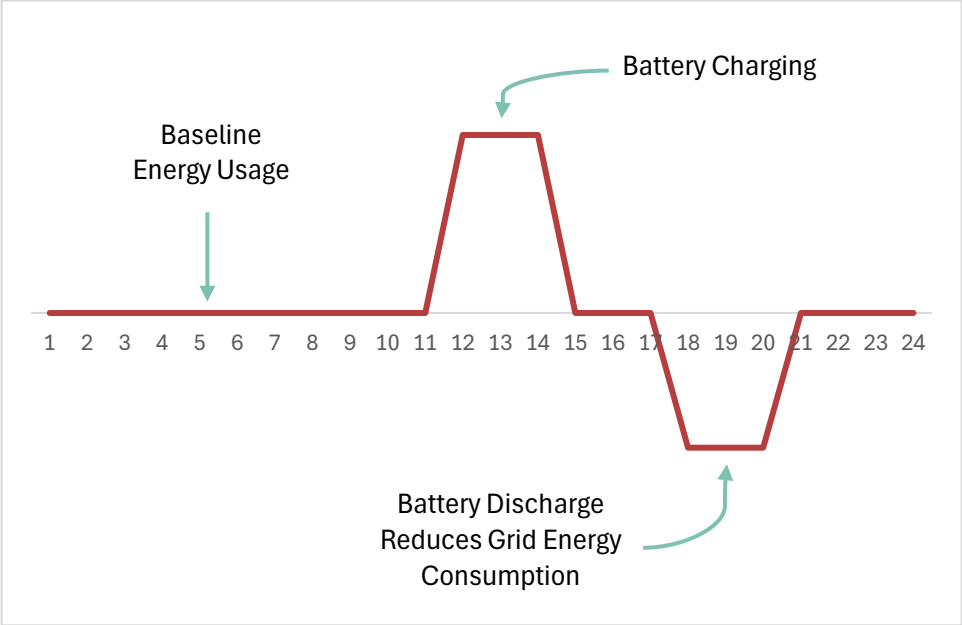
The BYO Battery product assumes the customer already owns a battery system, often paired with rooftop solar, and enrolls it in a demand response program. The utility compensates participants for allowing controlled dispatch of their battery during peak events. Eligibility for BYO Battery is linked to

the rooftop solar frozen forecast of adoption for the region (see Technical Appendix F – Electricity Demand Forecast). With the forecast in MW an average size of 7.2 kW[20] was used to calculate the number of solar installations. Five percent of forecasted solar installations are assumed to naturally adopt and attach a home battery system to be eligible for the BYO Battery product. It is assumed that 80% of the battery capacity is enrolled in the program for load shifting with an 85% roundtrip efficiency.

Battery+

Battery+ represents systems installed specifically for demand response purposes, where the program sponsor covers the equipment costs in exchange for direct operational control. The Battery+ demand response product uses the residential rooftop solar potential analysis (see Technical Appendix J – Rooftop Solar Methodology and Potential) to define eligibility. This assumes that all achievable rooftop solar units can have a battery attached and includes the cost of the battery procurement for the demand response product. The Battery+ product is designated as frequently deployable because the demand response operator has fronted the cost of the battery storage system in exchange for being allowed to use it consistently to load shift.

Figure I - 13: Battery Storage – 24 Hour Demand Response Deployment Shape



[20] Based on NREL's 2022 Annual Technology Baseline industry median sizing for a residential PV system

Table I - 14: Battery Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
BYO Battery	27	$36
Battery+	452	$278

C&I Demand Curtailment

Demand curtailment targets large commercial and industrial (C&I) customers who can temporarily reduce operations or shift processes in response to dispatch calls. Programs may combine manual actions, automated controls, or behavioral adjustments, depending on facility capability.

Eligible participants for this product have monthly average demand exceeding 150 kW and receive incentives for verifiable reductions during events. This product type provides short-duration capacity during the most constrained system hours and is treated as a limited-deployment resource.

Figure I - 14: C&I Demand Curtailment - 24 Hour Demand Response Deployment Shapes

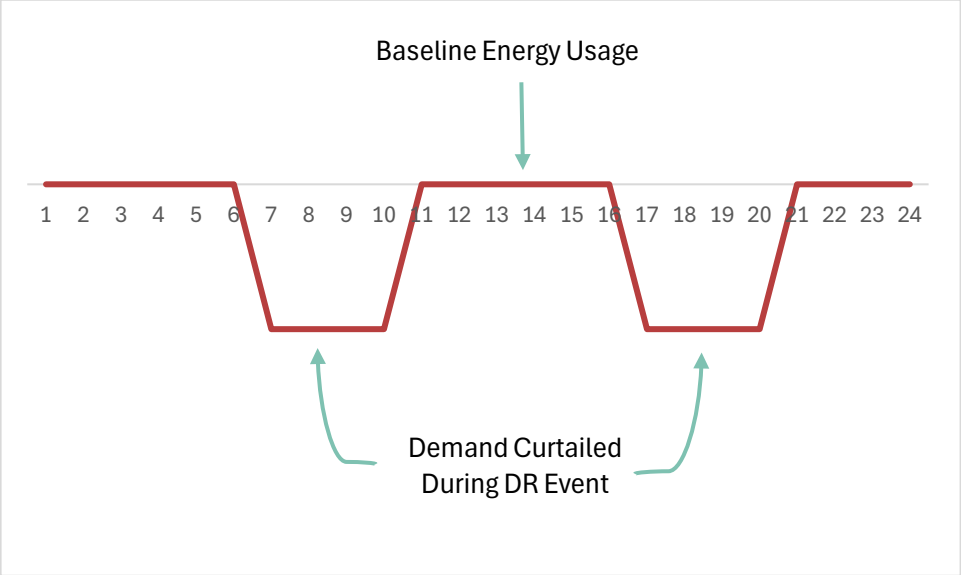


Table I - 15: Demand Curtailment Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ComCurtail	89	$38
IndCurtail	112	$33

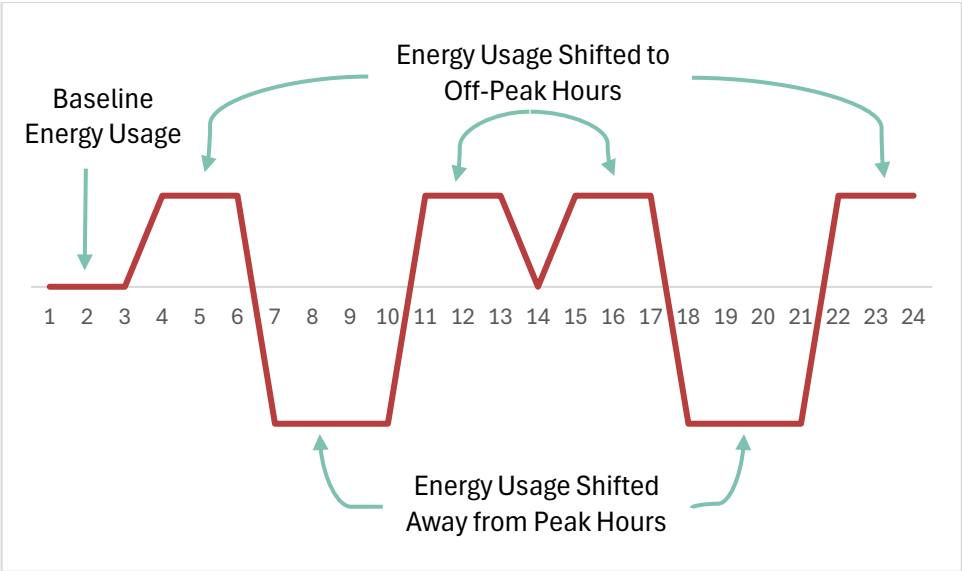
Price-Based Demand Response

Price-based demand response relies on dynamic rate structures that encourage customers to modify usage based on electricity prices. These products influence multiple end uses simultaneously and are evaluated using the top-down method. Eligibility for all price-based demand response products is based on advanced metering infrastructure (AMI) saturations available in EIA Form 861 data[21] and plans for AMI deployment by zone.

Time-of-Use

Time of Use (TOU) is a rate structure where electricity rates are set lower during off-peak hours and higher during peak hours to encourage customers to shift their energy usage to preferrable time periods. There are no events called, and the rate structure remains the same. The TOU product is assumed to be opt-in, meaning that customers voluntarily elect to participate in this rate structure. Opt-out TOU rates, in which customers are automatically enrolled in the rate structure, do exist elsewhere in the country, but are not currently common in the region. The opt-in structure generally has less potential program participation than an opt-out. Peak hours align with peak targets for direct load control demand response products, set for four hours in the AM and PM in the summer and four hours in the AM in the Winter. The reduced load during these hours is assumed to be shifted to the three hours immediately before and after the on-peak hours.

Figure I - 15: Time of Use – 24 Hour Demand Response Deployment Shape



[21] Energy Information Administration Annual Electric Power Industry Report, Form EIA-861 detailed data files: https://www.eia.gov/electricity/data/eia861.

Table I - 16: Time of Use Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ResTOU	194	$33

Critical Peak Pricing

Critical Peak Pricing (CPP) is a rate structure that is designed to encourage reduced energy consumption during periods of high wholesale market prices or system contingencies. CPP typically offers a slightly discounted energy rate year-round in exchange for setting higher rates during a limited number of "critical peak" events to discourage energy usage during those times. These critical peak rates are typically significantly higher than peak rates one might see on a TOU rate, and thus have a higher level of load impact. However, CPP dispatch is assumed to be limited. CPP potential is modeled for residential, commercial, and industrial customers in separate demand response products

Figure I - 16: Critical Peak Pricing - 24 Hour Demand Response Deployment Shape

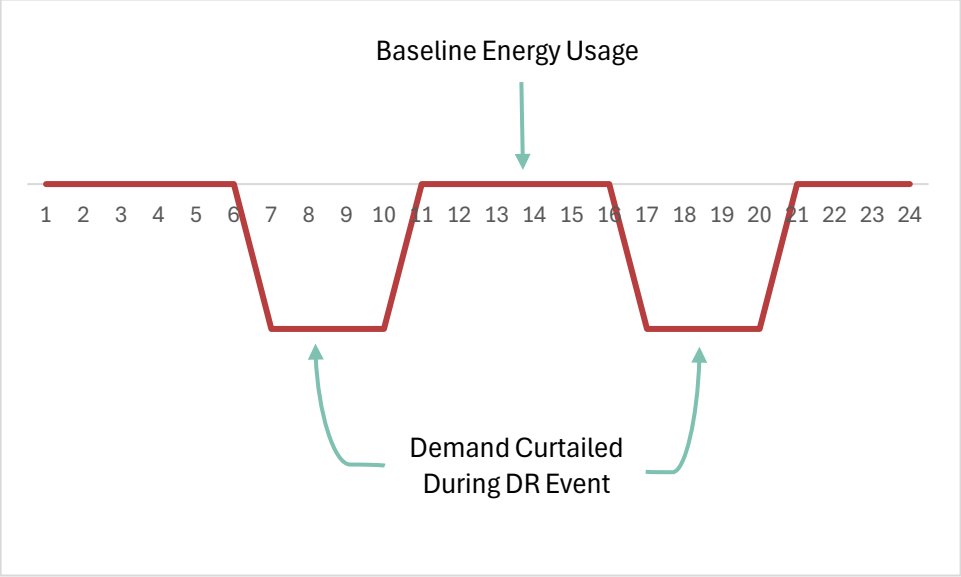


Table I - 17: Critical Peak Pricing Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ResCPP	102	$62
ComCPP	37	$58
IndCPP	22	$94

Demand Voltage Regulation

Many utilities can reduce the voltage on their primary distribution circuits but still be within the acceptable range defined by the American National Standards Institute.[22] This voltage reduction has minimal impact on the end-use customer and results in lower losses, thus saving energy. This could be done on a permanent basis (conservation voltage reduction, or CVR) or during short-duration events (demand voltage regulation, or DVR). DVR lowers the system operating voltage during the forecast peak window, thus reducing the energy delivered, which results in lower demand. DVR can be used daily to reduce energy use in periods of peak load and high prices but avoid reducing load when prices are low. DVR is currently being implemented by a number of regional utilities, namely Avista, PGE, Idaho Power, and PacifiCorp. For the modeling zones that align with these utilities it is assumed that there is no DVR potential available.

Figure I - 17: Demand Voltage Regulation – 24 Hour Demand Response Deployment Shape

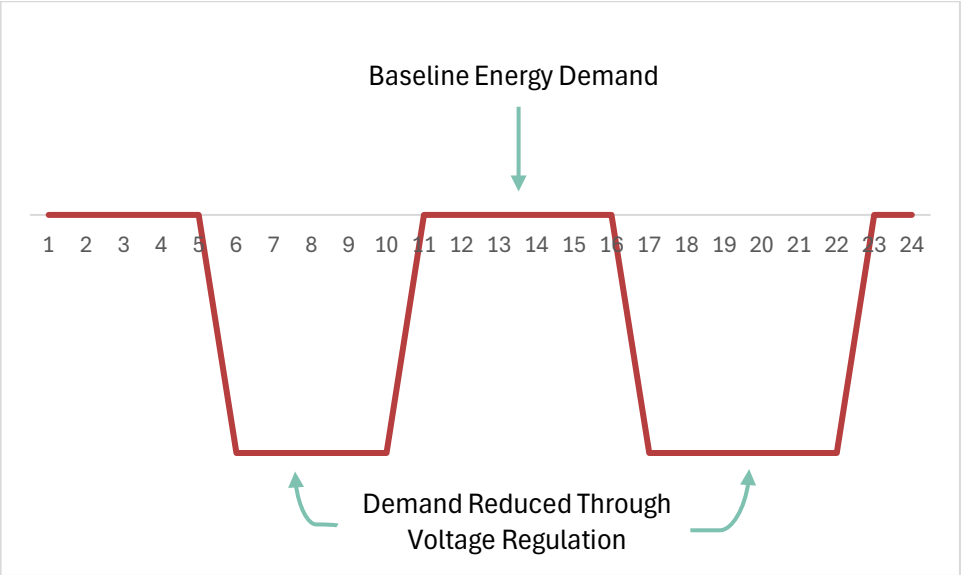


Table I - 18: Demand Voltage Regulation Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
DVR	322	$-6

[22] ANSI C84.1-2020 sets nominal voltage ratings and operating tolerances for 60 Hz electric power systems: https://blog.ansi.org/ansi/ansi-c84-1-2020-electric-voltage-ratings-60-hz.

Demand Response Technologies Considered but Not Modeled

Data Center Load Flexibility

Data centers represent a rapidly growing and increasingly significant load class within the electric system, driven by continued expansion in cloud computing, artificial intelligence, and digital services. As electricity demand from data centers grows, so does interest in their potential to provide demand flexibility during periods of system stress or elevated energy prices. Several pathways exist through which data center loads can be adjusted or managed in response to grid conditions, though these capabilities vary widely by facility design, workload type, and operational constraints.

One source of flexibility comes from workload management. Certain computing tasks – particularly machine learning model training, batch processing, and other non-time-sensitive workloads – can accommodate delays or temporary curtailment, allowing energy consumption to be shifted away from peak periods. In addition, many data centers maintain on-site generation and storage assets, typically in the form of diesel backup generators or battery systems installed for reliability purposes. In some cases, these resources can be used strategically to reduce grid demand during peak hours, effectively providing load relief without interrupting service. Data centers may also provide flexibility through geographic load shifting, whereby workloads are dynamically reallocated across facilities in different regions in response to local grid conditions. This approach has been demonstrated in practice, including a pilot conducted by Google in partnership with North Wasco PUD in Oregon, which showed the feasibility of using demand response signals to shift data center load geographically.[23]

Despite this potential, data centers are not explicitly modeled as a demand response resource in this analysis. There is currently insufficient publicly available data on the cost, duration, reliability, and scalability of data center flexibility to support robust modeling assumptions. Participation is highly dependent on site-specific configurations, contractual arrangements, and operational priorities, and existing examples remain limited in scope. Nevertheless, data centers represent an important emerging opportunity for future demand-side flexibility and warrant continued monitoring as technologies, market structures, and operational practices mature.

Vehicle to Grid

Vehicle-to-Grid (V2G) services represent a potentially significant future demand response and grid-support resource, enabling bidirectional power flow between electric vehicles (EVs) and the grid. Under a V2G framework, aggregated EV batteries can provide peak load reduction, load shifting, ancillary services, and resilience benefits by discharging stored energy during periods of system stress and recharging during off-peak hours. However, despite its technical feasibility, V2G remains at

[23] https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption.

an early stage of commercial deployment in most regions, with limited large-scale operational experience.

V2G is not explicitly modeled in this analysis due to several unresolved implementation and market barriers. These include low penetration of V2G-enabled vehicles and chargers, lack of standardized interconnection and compensation frameworks, uncertain customer participation and behavioral response, and concerns around battery degradation and warranty impacts. In addition, most existing EV programs focus on unidirectional managed charging, which provides more predictable and lower-cost load shifting benefits without requiring bidirectional hardware or complex control systems. While V2G may become a meaningful demand response resource in the longer term – particularly for fleet-based applications such as school buses, delivery vehicles, or municipal fleets – it is excluded from the current modeling due to its limited near-term scalability, uncertain cost-effectiveness, and absence of established market structures to support reliable dispatch.

Modeling Demand Response Supply Curves

Binning and Preparation for OptGen

To model demand response in the Council's capital expansion model (OptGen), it is necessary to aggregate or bin demand response products together to represent larger resource options for the model to select. In prior power plans, the sole criteria used to bin demand response was cost – products within the same levelized cost "bin" were aggregated together.

For the Ninth Plan, the additional granularity offered by the OptGen model, both in terms of sub-regional modeling zones and hourly modeling capabilities, allows additional factors to bin demand response for modeling. The ultimate bundling strategy for the Ninth Plan utilizes three factors to aggregate demand response products: modeling zone, levelized cost, and deployment capabilities. There are seventeen modeling zones, six levelized cost bins, and two deployment types.

Table I - 19: Demand Response Modeling Bins

Modeling Zone Bin	Levelized Cost Bin	Deployment Type Bin
AVA	< $20	Frequent
BPA_IDMT	> $20 - $50	Limited
BPA_OR	> $50 - $80	
BPA_WA	> $80 - $110	
CCPUD	> $110 - $140	
DCPUD	> $150	
GCPUD		
IPCO		
NWMT		

Modeling Zone Bin	Levelized Cost Bin	Deployment Type Bin
PACE		
PACW		
PGE		
PSE_Central		
PSE_North		
PSE_Olympia		
SCL		
TPWER		

Figure I - 18 and Figure I - 19 show the regional demand response potential, by levelized cost bin, for frequent deployment and limited deployment demand response products, respectively.

Figure I - 18: Frequent Deployment Demand Response Supply Curve by Levelized Cost Bin

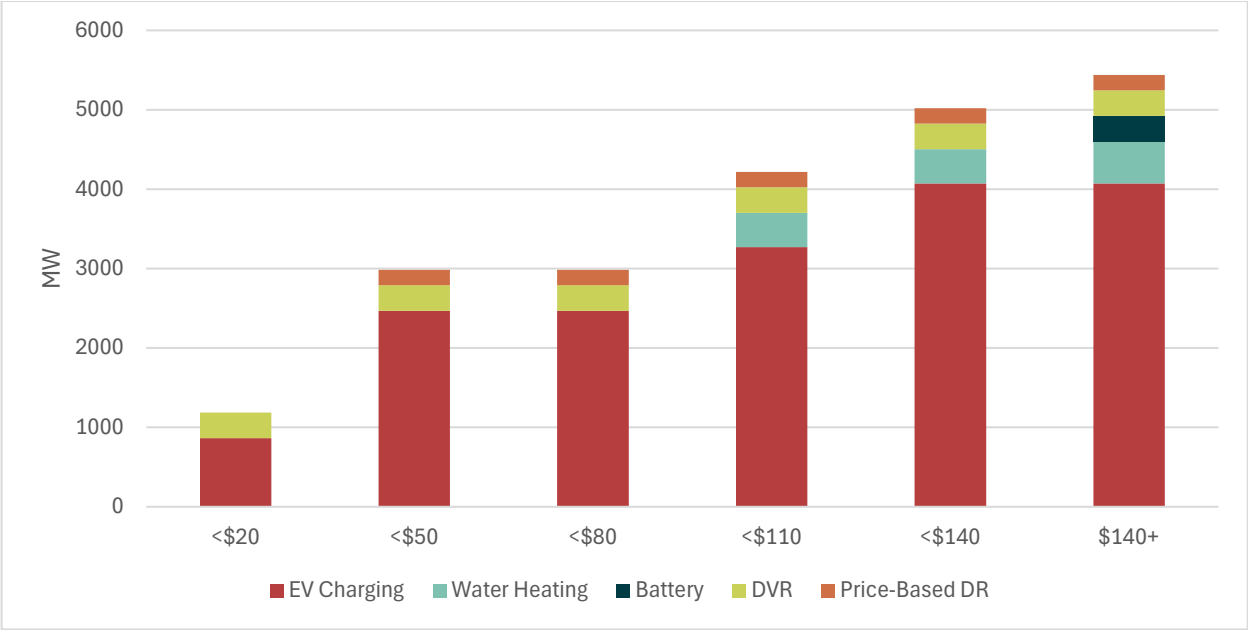
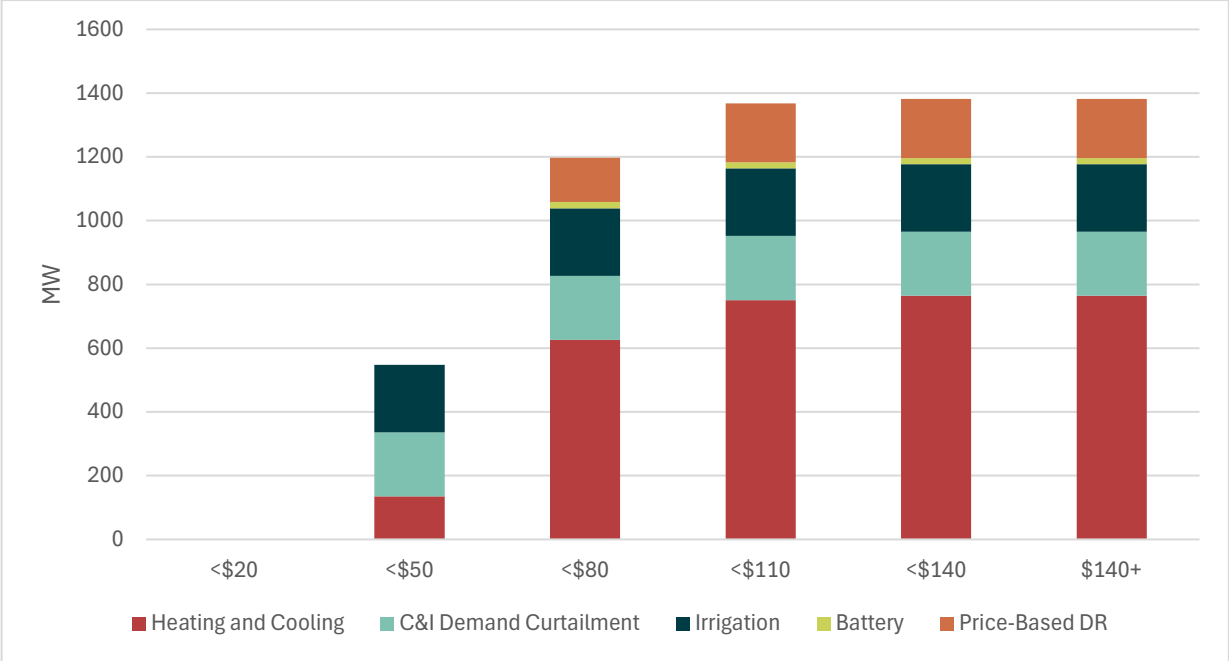


Figure I - 19: Limited Deployment Demand Response Supply Curve by Levelized Cost Bin



Demand Response Interaction with Energy Efficiency

Demand response and energy efficiency are part of a larger suite of activities that utilities use to call upon their end-use customers to modify their demand (collectively referred to as demand side management). Both demand response and energy efficiency rely upon end-use equipment and thus there is overlap between the potential of each. The interaction may be complementary or reductive, meaning that installing efficiency measures may increase or decrease the availability of demand response. This is reflected in the modeling for the Ninth Plan through residential water heating. Since demand response potential for ERWHs and HPWHs is developed through separate demand response products, a change in the water heating equipment saturations would naturally affect total potential available for each. Adoption of the ~450 aMW of residential HPWHs in an energy efficiency program would significantly increase the HPWH equipment saturation, while also lowering the ERWH equipment saturation.[24] Given the relatively low-cost nature of the efficiency measure (~$60/MWh), water heating equipment saturations that reflect the adoption of the HPWH efficiency potential were used to develop the water heating demand response potential that was ultimately modeled. This results in the reduction of 290 MW of ERWH demand response and the addition of 195 MW of HPWH demand response as electric resistance transitions to heat pump.

[24] Technical Appendix H – Conservation Methodology and Potential has more details on the conservation supply curve development for water heating and other products.

Adjusting for Load Futures and Scenarios

There is ultimately not a single set of demand response supply curves for the Ninth Plan, but rather many variations, depending on the load future and analysis scenario being run in the model. Load futures and scenarios are similar in that they can both have changing assumptions that alter the shape, magnitude, and/or costs of the demand response supply curves; however, they are different in that all load futures are present in every scenario, but scenarios are distinct from one another.

Table I - 20 summarizes the adjustments made to the demand response supply curves, depending on the specific load future and scenario. As the table highlights, there are two main drivers of change for the supply curves, depending on the load future and scenario, and they are: the presence of high building electrification and whether there is any assumed delay in demand response availability.

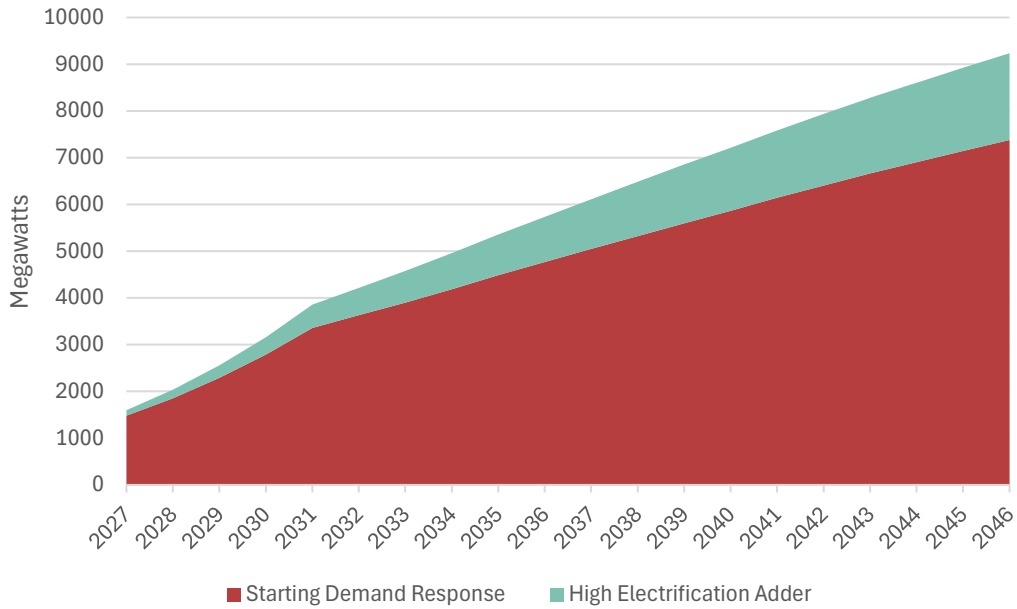
Table I - 20: Adjustments to Demand Response Supply Curves

Analysis Sensitivities	High Electrification	DR Availability Delayed	Storage Availability Delayed
Changing Hydro Operations	No	No	No
	Yes	No	No
Constrained World	No	No	No
	Yes	No	No
Evolving Federal Landscape	No	No	No
	Yes	No	No
Emerging Tech Uncertainty	No	No	No
	Yes	No	No
	No	No	No
	Yes	No	No
Transmission Availability Uncertainty, Short-Duration Storage Limitations	No	No	Yes
	Yes	No	Yes
Demand Side Resource Limitations	No	Yes	No
	Yes	Yes	No

The first driver, “High Electrification”, is a function of the load futures, and therefore, its effect shows up in every scenario and sensitivity tested. For context, the load futures contain a wide range of potential future load trajectories, and most relevant for demand response, some of these trajectories have lower (status quo) building electrification and some contain significantly higher electrification (see Technical Appendix F – Electricity Demand Forecast). As more loads are electrified, there is more demand response potential relative to the current practice baseline; therefore, load futures with higher building electrification will have higher available demand response. Note that higher electrification loads are only assumed for water heating and space heating end uses in Oregon and

Washington.[25] Figure I - 20 shows the incremental demand response available due to building and vehicle electrification every year over the 20-year horizon from 2027 to 2046.

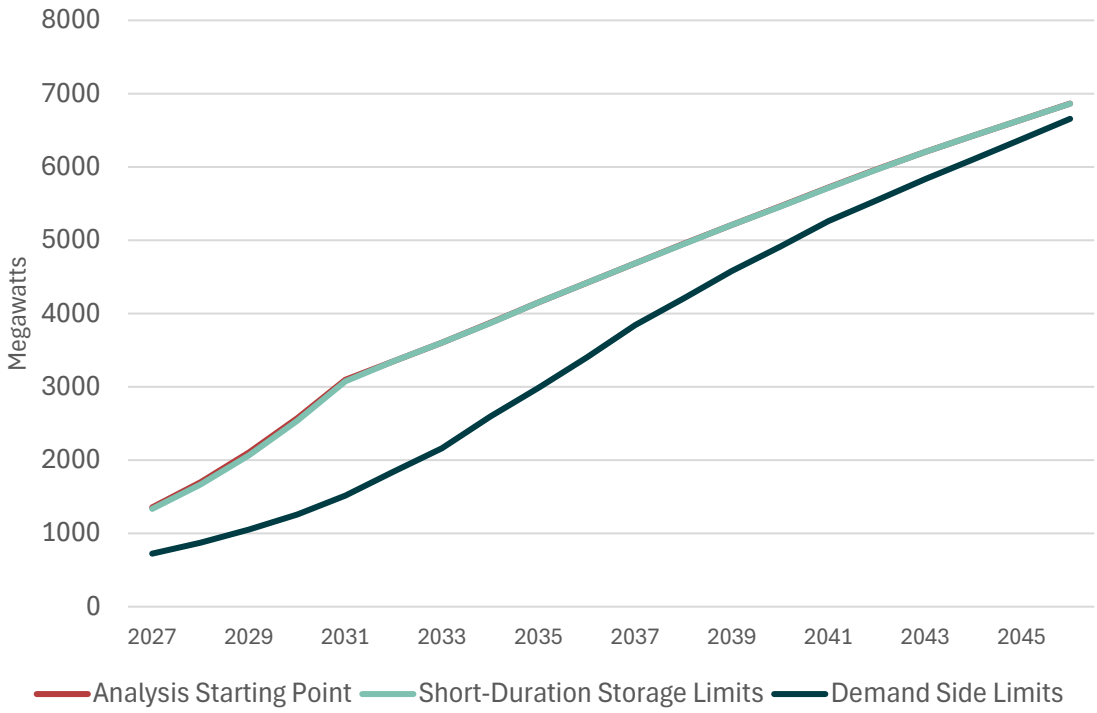
Figure I - 20: Demand Response Achievable Potential with Electrification



The remaining two drivers shown Table I - 20, relating to delayed storage availability and delayed demand response availability, are all a function of the sensitivity, and therefore their effects are isolated to each individual sensitivity.[26] The sensitivity is designed to examine how demand response, and other demand and supply side resources, may be selected differently depending on several different important factors. The sensitivity impacting demand response examines the availability of the resource with limitations introduced to short-duration storage availability and demand side resource availability. For short duration storage limitations, demand response products that use battery storage technology are limited in availability for the first six years of the study. For demand side limitations, all demand response products are limited in availability using slower ramp rates throughout the study that align with the ramp rates used for conservation in this scenario. Figure I - 21 shows the difference in annual achievable potential available in the analysis starting point versus the Demand Side Resource Limitations and Short-Duration Storage Limitations sensitivities.

[25] Consistent with the Ninth Plan load forecast.
[26] See Technical Appendix N – Scenario Modeling and Results.

Figure I - 21: Annual Demand Response Achievable Potential Compared to Limited Availability Sensitivities



Total Demand Response Potential

All the work described thus far in this appendix results in a final technical achievable demand response resource that is used to compete against other demand and supply side resources in the Council's capital expansion model. The final demand response resource can be illustrated by a supply curve, which shows the cumulative demand response potential available up to a given price point, in this case the net levelized cost. Figure I - 22 shows the final Ninth Plan technical achievable demand response supply curve, by sector, over the 20-yr period from 2027 to 2046. Figure I - 23 and Figure I - 24 show the summer and winter supply curves respectively. Each levelized cost bin is cumulative and includes all the potential from lower cost bins.

Figure I - 22: 2046 Achievable Demand Response Potential with Net Levelized Cost - Combined

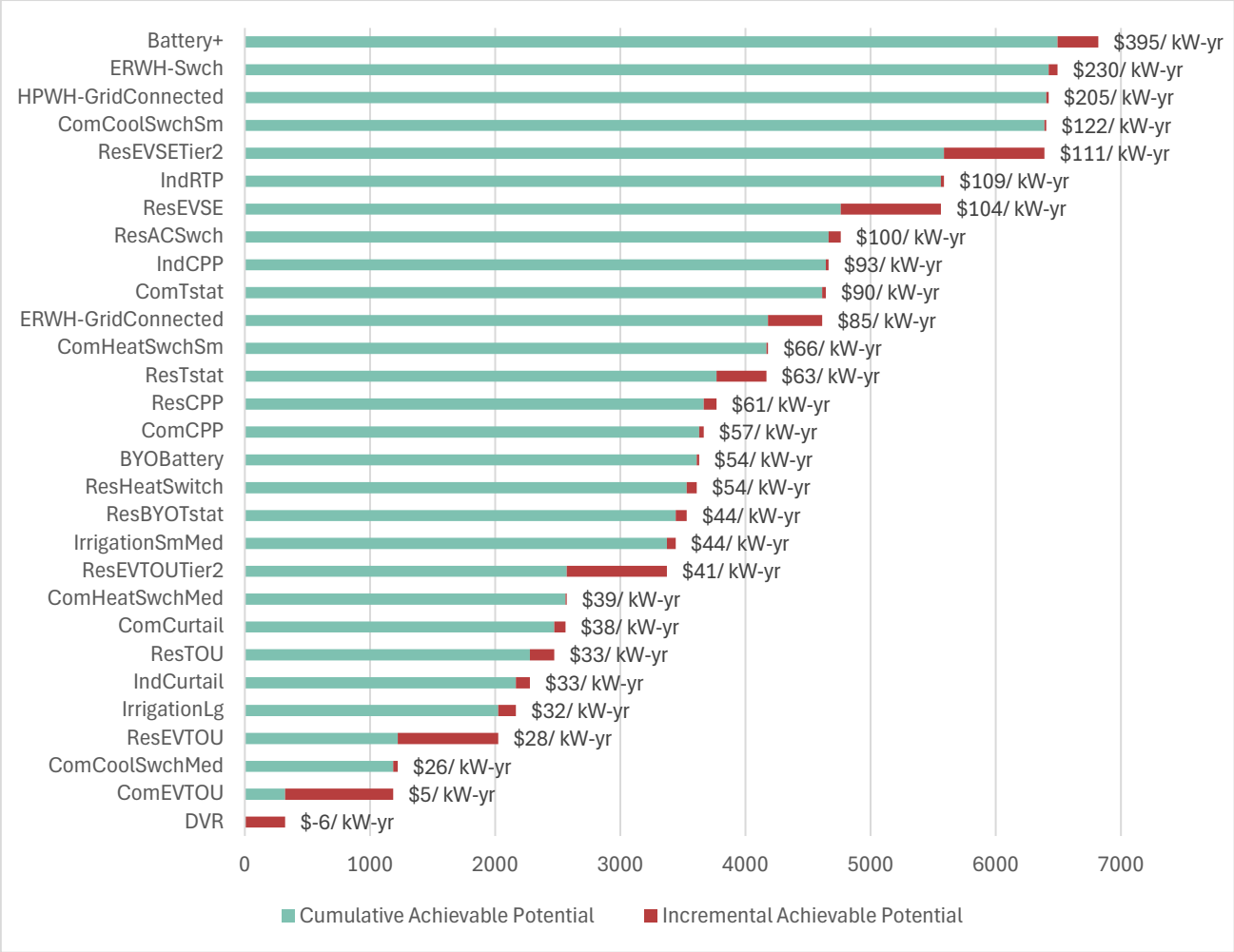


Figure I - 23: 2046 Achievable Demand Response Potential with Net Levelized Cost - Summer

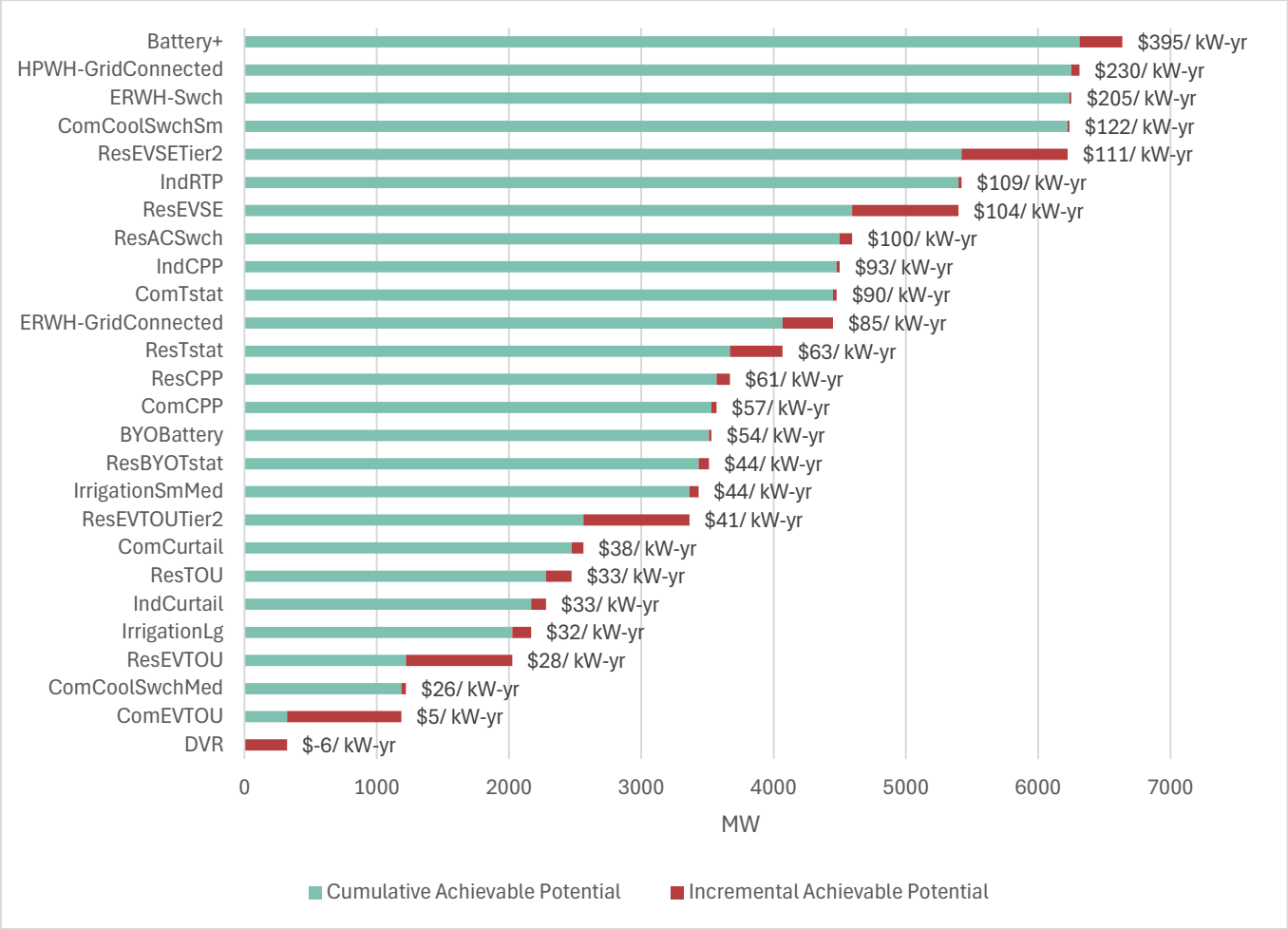
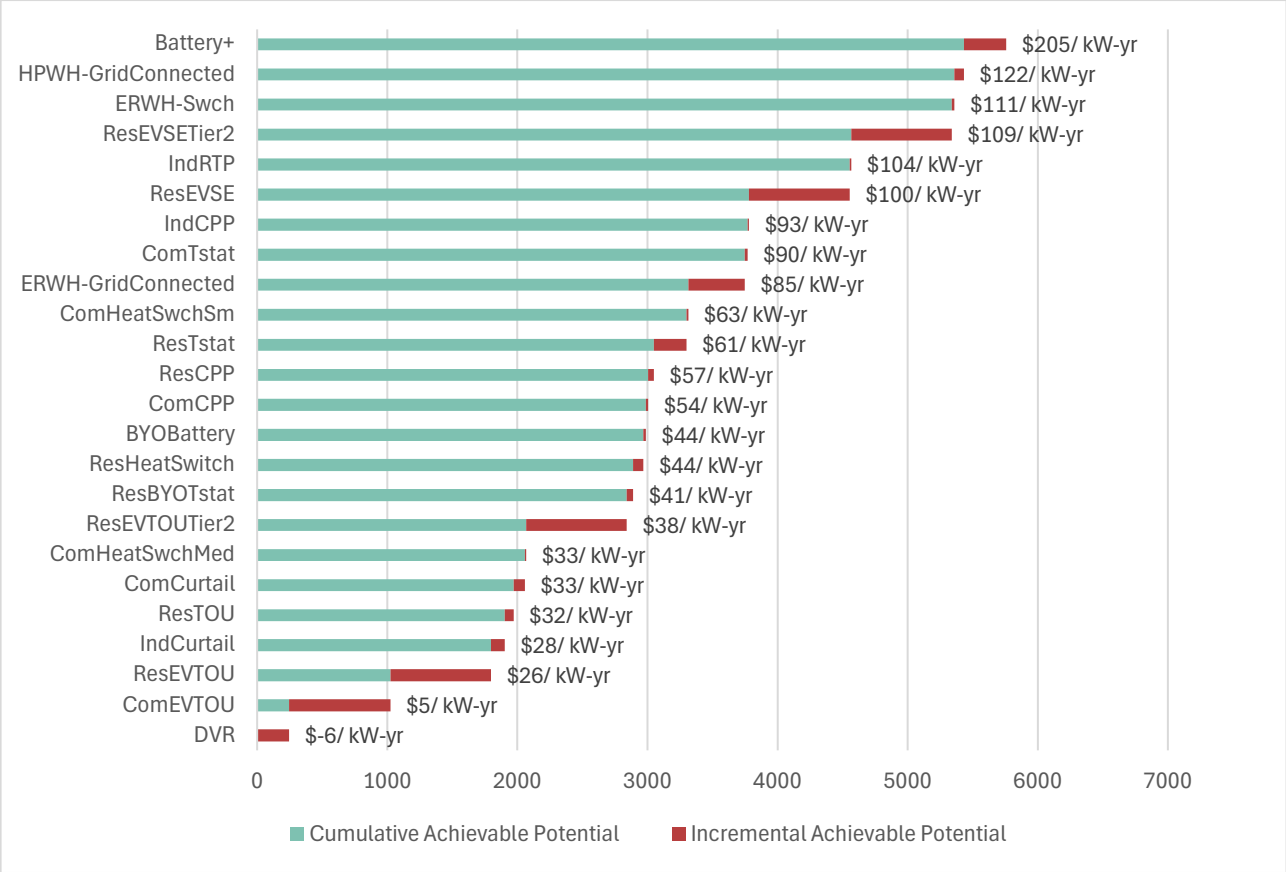


Figure I - 24: 2046 Achievable Demand Response Potential with Net Levelized Cost - Winter



Excel Workbooks and Tools

Ninth Plan demand response supply curves and the supporting workbooks can be found on the Council's Ninth Plan Technical Elements page[27] as well as directly in the 9thPlanDRSupplyCurves folder.[28]

Input Assumptions

All input assumptions reside within the Inputs folder.[29] All demand response product inputs reside within the DR_Database workbook.[30] This workbook contains the cost, impact, and deployment assumptions for all demand response products for the Ninth Power Plan, as well as much of the contextual data informing eligibility such as customer, stock, and load forecasts. Each demand

[27] https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.
[28] https://nwcouncil.box.com/v/ninthplanDRsupplycurves.
[29] Ibid. See "Inputs" folder.
[30] Ibid. See "DR_Database" workbook.

response product has specific assumptions for each of the 17 regional zones being modeled, roughly aligning with the region's balancing authorities. Inputs are pulled from this database to iterate through combinations of season, modelling zone, and impact and cost assumptions for all demand response products considered in order to develop total potential and net levelized costs. Descriptions of each demand response product and the different input parameters are listed here as well. Global input assumptions are located in the Inputs_Global_All workbook[31]. This includes the economic and system global inputs as well as the sector and end use shares used to disaggregate the load forecast and develop customer counts.

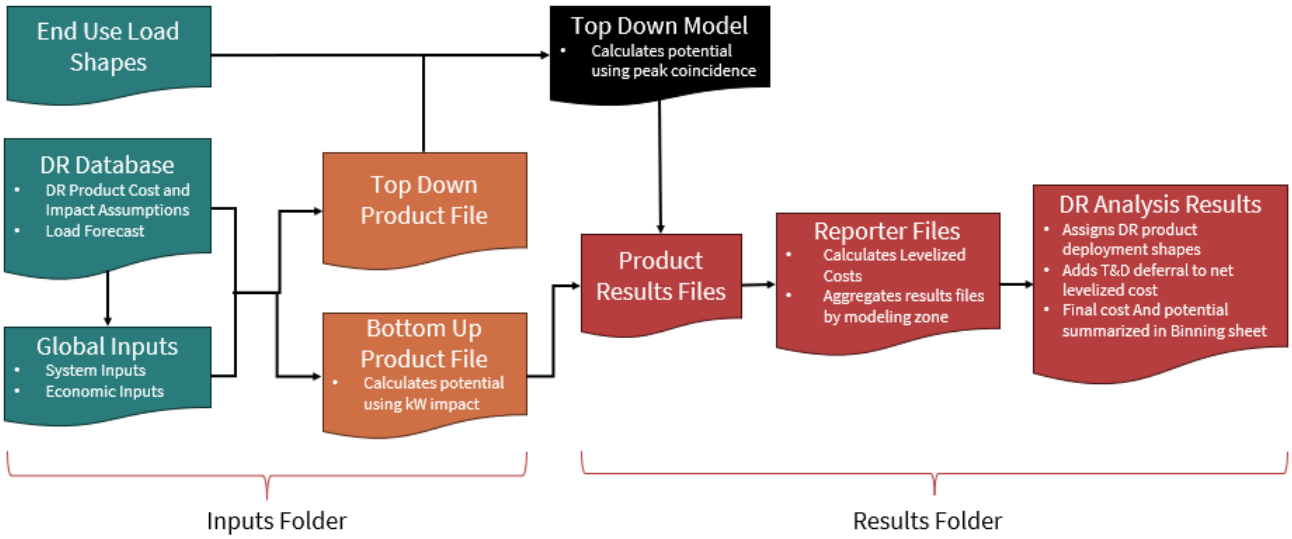
Modeling Steps

A number of workbooks are used to conduct the analysis developing achievable demand response potential. The analysis workflow and file and folder structure is summarized in Figure I - 25. The DRProductTopDown and DRProductBottomUp workbooks contain the template for how achievable potential is calculated for each iteration of demand response product, zone, and season for the bottom up and top down methodologies. In the ProductScenarioTemplate sheet of the DRProductBottomUp workbook, for example, dropdowns in the Region, Product Name, and Scenario Name cells allow the user to select different combinations that will then pull data from the demand response Database into the worksheet. The underlying formulas then calculate achievable potential for the plan years in columns DZ:FE. The Top Down methodology works somewhat differently, using the TopDownModel workbook to integrate the load forecast in the Global Inputs file, the end use load shape files, and inputs pulled into the DRProductTopDown file. VBA macros for both these DRProduct workbooks iterate through each combination of demand response product, modelling zone, and season, and export results files to the Results folder.[32] Each modelling zone has its own results folder, with a results file for each demand response product-season combination.

Levelized cost is calculated and potential aggregated using the Reporter_summer and Reporter_winter workbooks. VBA modules for both these workbooks create Reporter files for each of the 17 zones that are exported to the Results folder. Levelized cost figures as well as 20-year achievable potential are summarized in the Portfolio Summary sheets of these workbooks. The Reporter results files are aggregated using an R script and input into the Combined Data sheet of the DRAnalysisResults workbook.[33] This workbook assigns deployment shapes to each demand response product and incorporates T&D deferral credit into net levelized cost. Supply curves for each modeling zone can be viewed by toggling the Zone dropdown. Potential and cost are summarized in this appendix for the entire region with levelized costs developed as a weighted average of the costs for each zone.

[31] See “Inputs_Global_All” in the Inputs folder here: https://nwcouncil.box.com/v/ninthplanDRsupplycurves.
[32] See “Results” folder: https://nwcouncil.box.com/v/ninthplanDRsupplycurves.
[33] Ibid. See “DRAnalysisResults” workbook.

Figure I - 25: Supply Curve Analysis Workflow and File Structure



Where to Find More Information

For more information on these supply curve materials, please visit the Council's Ninth Plan website,[34] which contains a number of presentations, videos, and supporting materials for this work. You can also visit the Council's Demand Response Advisory Committee website,[35] which also contains presentations and discussions that helped guide and shape this work.

[34] https://www.nwcouncil.org/energy/ninthpowerplan.
[35] https://www.nwcouncil.org/energy/energy-advisory-committees/demand-response-advisory-committee.

Technical Appendix J: Rooftop Solar Methodology and Potential

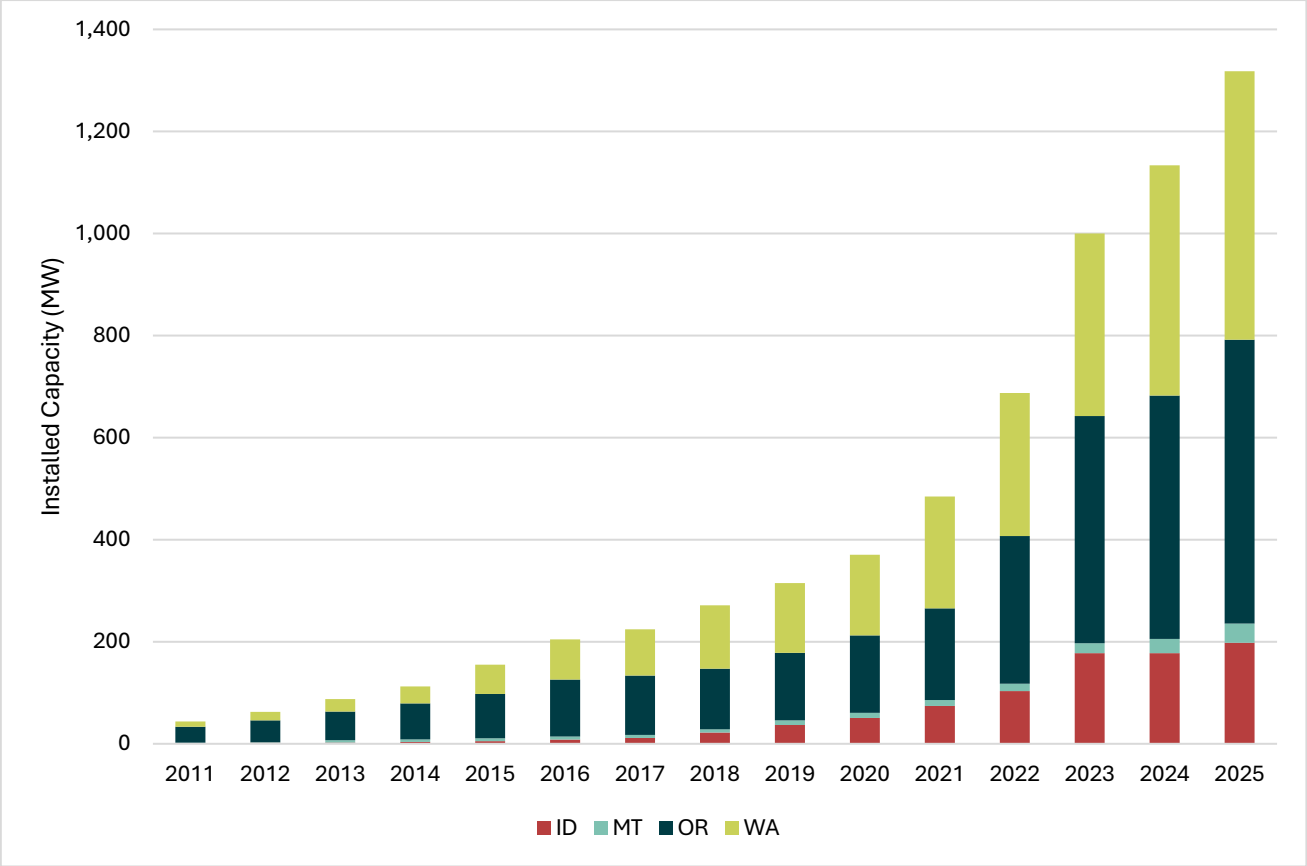
Contents

Background 1
Methodology for Estimating Rooftop Solar Potential 3
Building Stock and Roof Orientation 4
System Capacity and Energy 6
Solar Potential Development 10
Rooftop Solar Potential by Zone 14
Adjusting for Load Futures and Scenarios 14

Background

Rooftop solar installations in the Pacific Northwest have increased significantly in recent years. Figure J - 1 shows the installed rooftop solar capacity in the four Northwest states from 2011-2025. In 2011, there were 44 MW of rooftop solar capacity installed and that number has grown to over 1,300 MW in 2025.

Figure J - 1: Rooftop Solar Capacity by State 2011-2025



Recent power plans have included rooftop solar data in the load forecasts, which means it has been treated as a load reduction in the models. The Council has not included rooftop solar as a resource to complete with others in the modeling and optimization process, largely because of the historically high cost of these resources relative to other generating resources. However, the cost of rooftop solar panels has been declining rapidly to the point that they now may be more competitive with some utility-scale generating resources as well as demand-side resources. Therefore, because of declining costs and significant growth in installations, the Council is treating rooftop solar as a competitive resource in the Ninth Power Plan.

Rooftop solar refers to roof-mounted PV systems found in the residential, commercial, and industrial sectors. For the Ninth Plan, the Council developed detailed rooftop solar supply curves (levelized cost and energy production) for the residential and commercial sectors. The resource potential for rooftop solar was developed using bottom-up potential estimates like the approach used for energy efficiency. The bottom-up approach is based on the number of homes and businesses, and the amount of solar energy production for each, and then rolled up into regional potential estimates.

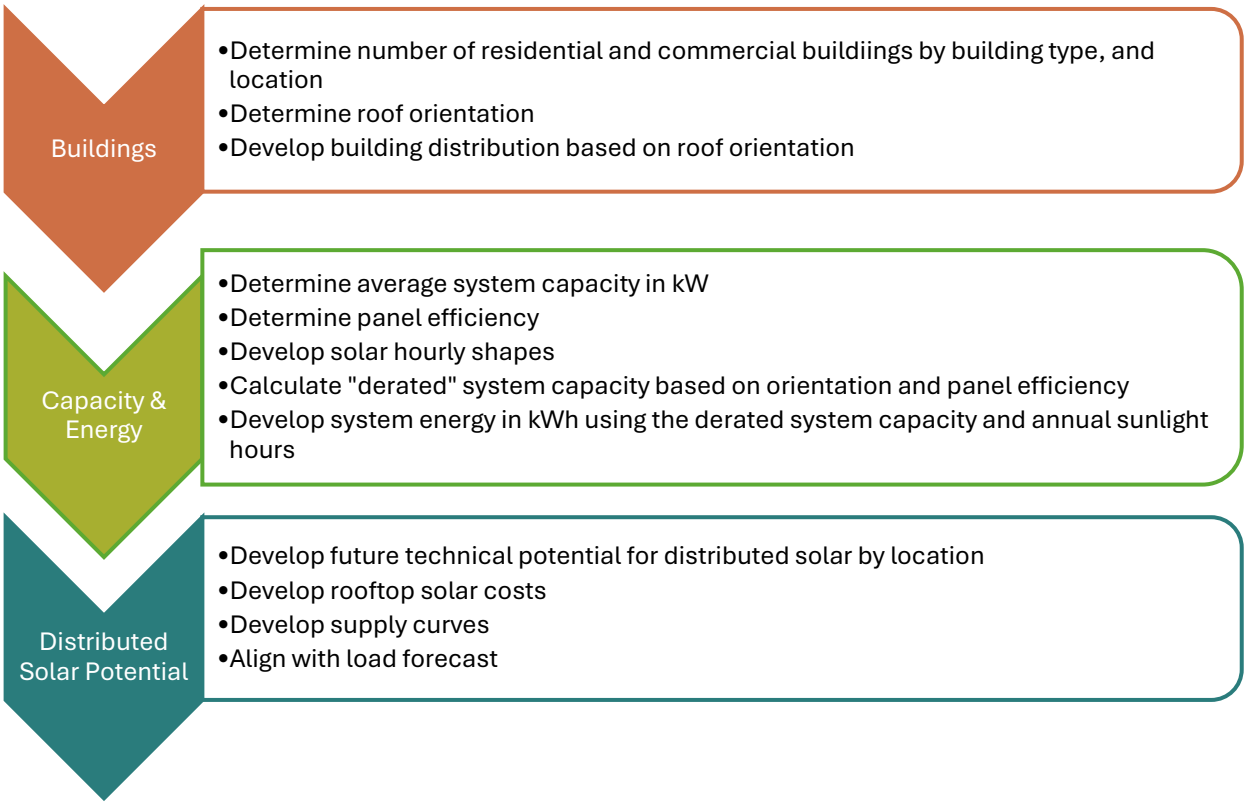
Rooftop solar installations are considered distributed energy resources (DERs) which refer to sources of electricity generation that are located at or near the point of consumption or “behind the meter” such as at a home or business. While DERs are a broad category, the Council focused on rooftop solar in the residential and commercial sectors for the Ninth Plan. These two applications are

included because the region has seen significant increases in installations, along with cost reductions. Other DERs may include engine generators (natural gas, gasoline, propane), fuel cells, behind-the-meter wind turbines, but are far less common than rooftop solar.

Methodology for Estimating Rooftop Solar Potential

The high-level methodology used to develop rooftop solar potential is described in Figure J - 2. It includes estimating the number of homes and buildings that could host a rooftop solar system and the possible panel orientations. The energy production (kWh) is then estimated by combining the installed capacity (kW), the panel efficiency, orientation, shape, and annual sunlight hours. Finally, the total achievable potential is estimated by combining the number of buildings, energy production per building, and achievability factors including ramp rates. More detail about this methodology is provided below.

Figure J - 2: High-level Methodology



Building Stock and Roof Orientation

Estimates for the number of homes and commercial buildings were developed using the Residential Building Stock Assessment (RBSA) and the Commercial Building Stock Assessment (CBSA).[1] Table J - 1 shows the number of homes and commercial buildings in 2027 and the final year of the planning period in 2046.

Table J - 1: Numbers of Homes and Commercial Buildings

	2027	2046
Number of Homes	4.9 million	5.6 million
Number of Commercial buildings	350,000	430,000

Lawrence Berkeley National Lab's (LBNL's) Tracking the Sun data[2] were used to identify building and panel orientation. The report describes trends among grid-connected, distributed solar PV and paired PV plus storage systems in the United States. Panel orientation has been relatively constant in recent years. The report indicates that 54% of systems installed are facing south, 24% facing west, and most of the remainder facing east. A greater share of non-residential systems faces exactly due-south, likely due to greater prevalence of ground-mounting and flat rooftops than in the residential sector. Table J - 2 provides average panel orientation data for 2022 (latest date included in the report). These panel orientations were used in the residential sector only.

Table J - 2: Panel Orientation - Residential[3]

Panel Orientation	2022
North	4%
East	16%
South	54%
West	24%
Flat	2%

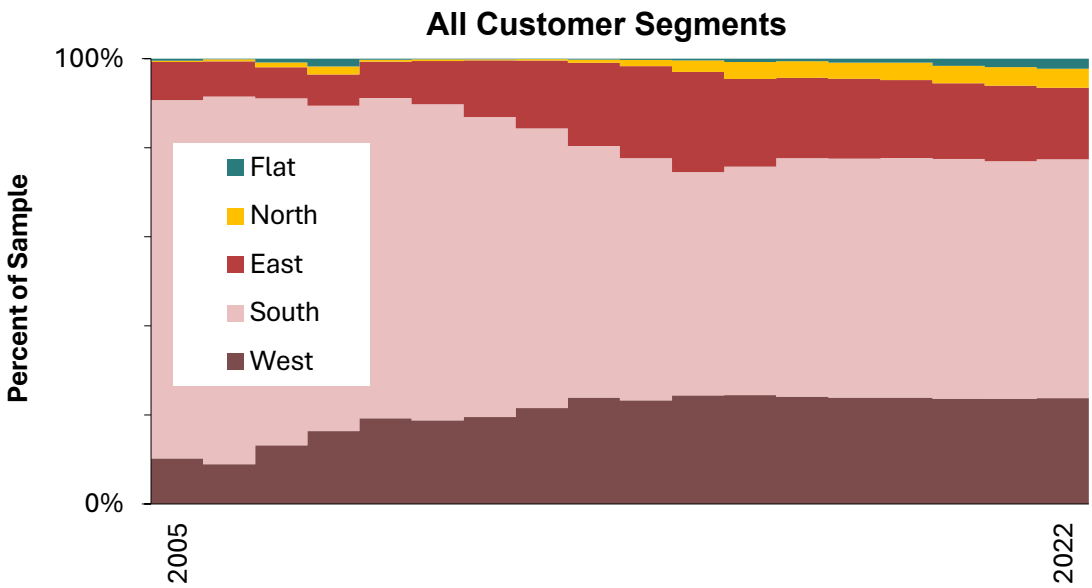
[1]Northwest Energy Efficiency Alliance 2022 Residential Building Stock Assessment. https://neea.org/residential-building-stock-assessment/

[2] LBNL Tracking the Sun Report Published on September 2023 can be found at https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.

[3] Ibid

Figure J - 3 provides panel orientation over time (2005 to 2022), illustrating how panel orientation has not changed significantly in recent years. For the Ninth Plan, the Council chose to use the 2022 average panel orientation in the analysis.

Figure J - 3: Panel Orientation Trends (2005 to 2022)[4]



For the commercial sector, south-facing orientation was assumed. The Council utilized NEEA CBSA data to estimate average roof area by building type for each of the four Northwest states. Then, based on data from LBNL,[5] the Council assumed 23% of roof area available for solar panels. The roof areas were then multiplied by 9.5 watts/sf[6] to obtain the system capacity. To simplify and reduce the number of permutations, two categories of buildings were created: large and small. Large buildings are those with greater than 100 kW of capacity, while small buildings have less than 100 kW of capacity. The overall average capacities by building category and state are shown in Table J - 3.

[4] Ibid
[5] Ibid
[6] L. Lisel, et.al., NREL Solar Ready Buildings Planning Guide, December 2009, https://docs.nrel.gov/docs/fy10osti/46078.pdf.

Table J - 3: System Size Estimates by State and Building Size Category

	Large Buildings	Small Buildings
ID	169 kW	38 kW
MT	226 kW	37 kW
OR	115 kW	43 kW
WA	135 kW	35 kW

System Capacity and Energy

Data for rooftop solar systems are reported by their system capacity. Ultimately, the amount of electricity produced by each installation is needed to estimate the potential electricity production per home or business. This section describes the process for developing these energy estimates.

Annual Sunlight Hours

Solar panels produce electricity only when the sun is shining, so it is important to estimate the annual sunlight hours, which can vary by location. Data from online sources as well as the Energy Trust of Oregon were used to estimate average sunlight hours by state. Table J - 4 shows the annual sunlight hours by state used in the analysis.

Table J - 4: Annual Sunlight Hours

State	Average Annual Sunlight Hours
Idaho	1497
Oregon	1171
Washington	1085
Montana	1537

Panel Efficiency

Module efficiencies vary considerably by manufacturer; however, LBNL's research[7] indicates the average panel efficiency for residential is 20.8%. Panel efficiency can be influenced by many factors such as temperature, irradiance level (sunshine), cell type and color, interconnection of the cell, shade, orientation, location, tilt, time of year (e.g., weather conditions and position of the sun) and contamination (e.g., dust, dirt, bird droppings, debris).

[7] LBNL Tracking the Sun Report Published on September 2023 can be found at https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.

Panel Capacity

Residential rooftop solar system sizes have been increasing over the past two decades. The median sizes in most states are now above 8 kW. The rated capacity was derated to account for orientation and panel efficiency. Table J - 5 provides system size by state for 2022 based on installations for the Northwest.

Table J - 5: System Size by State (2022 Installs)[8]

State	Average kW	Average Derated kW
Idaho	8.44	5.45
Oregon	8.87	5.72
Washington	9.47	6.11
Montana	10.80	6.97

Panel Energy

The energy production from rooftop solar panels was calculated by multiplying the derated panel capacity (kW) by the annual sunlight hours. Table J - 6 provides the calculated energy (kWh) values.

Table J - 6: Calculated Panel Energy

State	Average kWh
Idaho	8,150
Oregon	6,700
Washington	6,630
Montana	10,707

Solar Shapes

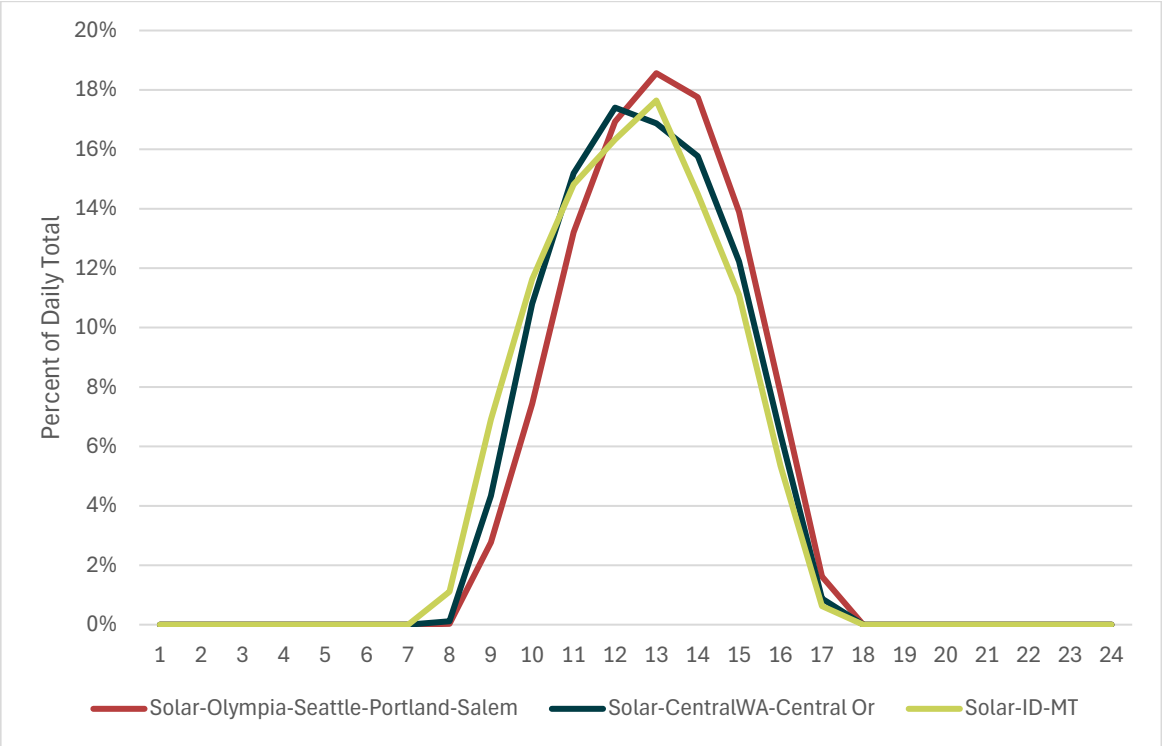
Solar profiles were developed for utility scale solar in the Ninth Power Plan (see Technical Appendix G – New Generating Resources). These same solar profiles are used for the rooftop solar assessment. The profiles correspond to three main areas in the region: West (west of the Cascades), Central (Central Oregon and Washington), and East (Idaho and Montana[9]. The profiles were normalized for

[8] Ibid

[9] There are two shapes (North/South) for each of the areas (West, Central, East) for a total of six shapes. However, the difference between the north and south shapes for each area is minute and not distinguishable in the graph, so only three shapes are shown.

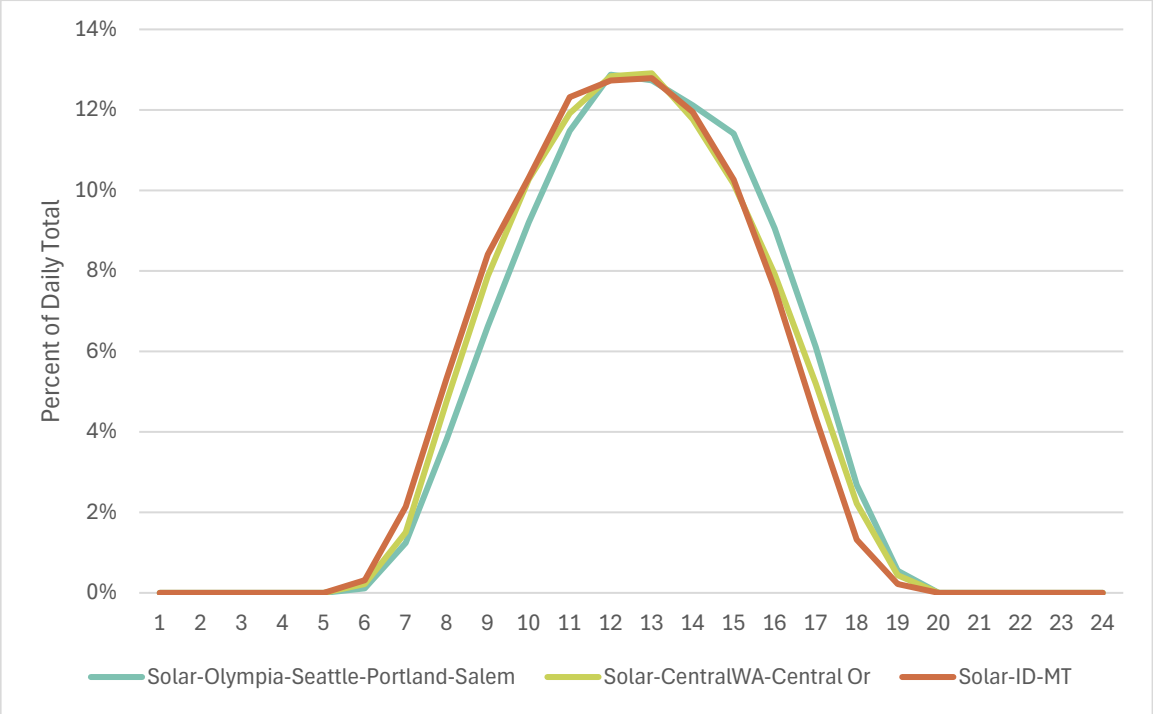
use in ProCost[10]. A sample of the solar shapes are shown in the next two figures. Figure J - 4 shows the peak day shape for January, and Figure J - 5 shows the peak day shape for August.

Figure J - 4: Solar Shapes – Peak Day January



[10] ProCost is the Council's Excel-based tool for calculating the levelized cost of energy efficiency and behind the meter solar measures: https://rtf.nwcouncil.org/work-products/supporting-documents/procost.

Figure J - 5: Solar Shapes – Peak Day August



Costs

Costs for residential systems were calculated using the average cost of $3.50 per watt. Costs are based on Energy Trust of Oregon and LBNL data. The cost per watt is then multiplied by the system size by state and by 1,000 to convert from watt to kW. Table J - 7 provides the calculated system costs by state. The analysis also includes an inverter replacement cost of $1,000. The inverter is assumed to be replaced after ten years (inverter life), while the life of the solar panels is assumed to be 25 years. This results in a one-time cost of $1,000 in year 10.

Table J - 7: Residential System Costs

State	$/watt	System Size (kW)	Total Cost
ID	$3.5	8.4	$29,560
MT	$3.5	10.8	$37,825
OR	$3.5	8.9	$31,070
WA	$3.5	9.5	$33,168

For the commercial sector, the cost was found to be $2.60/watt for small commercial systems and $2.17/watt for large commercial systems.[11] The data show that the cost per watt scales with system size so the resulting $2.60 per watt for commercial is lower than the $3.50 per watt for residential.

The federal investment tax credits (ITC) are included based on the specific scenario and sensitivity.

Solar Potential Development

Technical Potential

Technical Potential was calculated using the building stock multiplied by the derated capacity and energy values by panel orientation. Like energy efficiency, the technical potential is the maximum possible amount of energy that could be produced by installing rooftop solar panels on all homes in the region.

The formula for calculating the energy production of a solar system is detailed below:

$$\begin{aligned} &Energy\ Production\ (kWh) \\ &\qquad = Panel\ Capacity(kW) * Annual\ Sunlight\ Hours(Hrs) * System\ \ Loss\ Factor \\ &\qquad * Orientation\ Derating \end{aligned}$$

Once the energy production per home is calculated, it can then be multiplied by the number of homes to get to the technical potential.

Achievable Potential

Achievable potential is the result of applying various achievability factors to the technical potential. It is an attempt to estimate what is realistically achievable over the 20-year planning period. The standard maximum achievability assumed for rooftop solar installation is 85 percent. This factor has been used since the 1980's and attempts to capture the reality that even if a measure is paid for in full, there will still not be 100 percent adoption. There are also local limitations that impact the applicability of solar panels such as being located next to a tall building or in a dense forest. The locational limitations factor is estimated to be 15% and is based on professional judgement and confirmed by our advisory committees. Finally, the Council's load forecast included a conservative amount of rooftop solar adoption consistent with historical amounts. To avoid double counting that assumed adoption, a factor of 9.89 percent derates the achievability further. This brings the total maximum applicability to 60 percent. Table J - 8 summarizes these factors.

[11] LBNL Tracking the Sun Report Published on September 2023 can be found at https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.

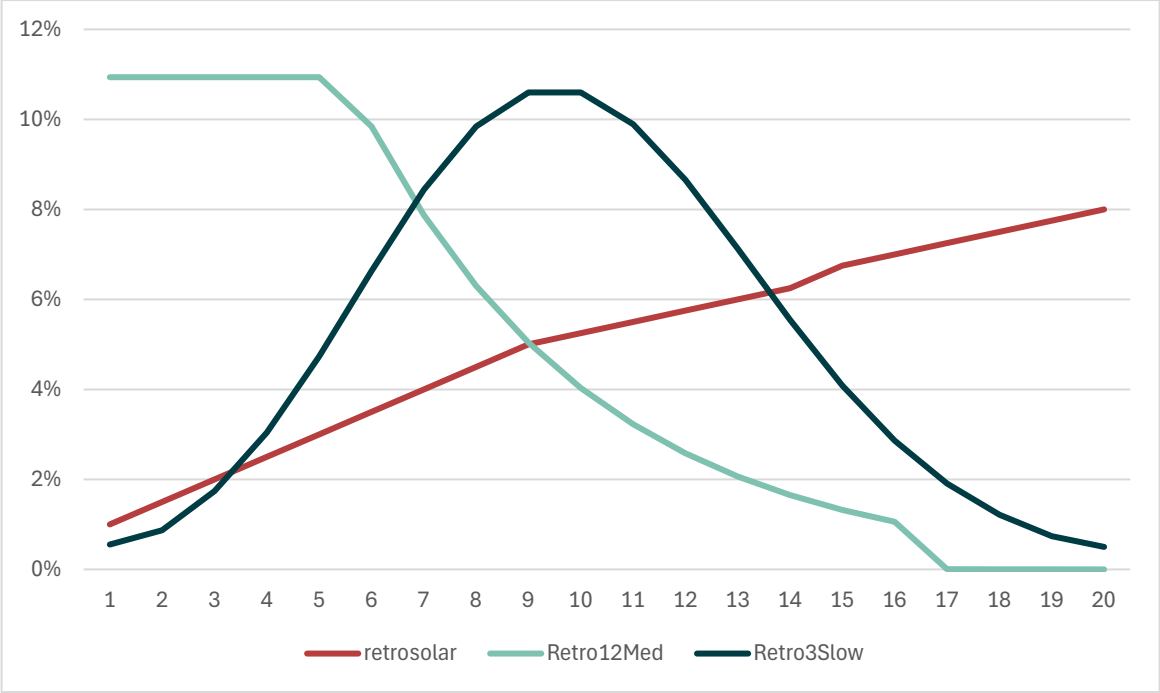
Table J - 8: Achievability Factors

Achievability Factor	Amount
Standard Max Achievability	85%
Included in Load Forecast + Saturation	9.86%
Locational Limitations	15%
Total Max Achievability	60%

In addition to the total achievability factors, limits are placed on the annual achievability using ramp rates. Ramp rates are a way to establish a pace of installation over time. For example, there are many factors that would prohibit, for example, the installation of rooftop solar on all available homes in the first two years. The ramp rates are the mechanism for simulating the maximum amount each year, and usually assumes subsequent years are increase as a program or infrastructure becomes more mature. For the rooftop solar analysis three ramp rates were applied (see Figure J - 6):

- Retrosolar – starts with a modest 1 percent and increases steadily over time to 8 percent per year. This rate is used for most locations.
- Retro3slow – starts slowly at less than 1 percent and then climbs quickly to just over 10 percent per year and then tails off again by year 20. Used in areas where the solar adoption rate is moderate.
- Retro12med – starts at 11 percent per year for five years and then drops off until all the potential is reached in year 17. Used in areas where the solar adoption rate is strong.

Figure J - 6: Ramp Rates for Rooftop Solar



Rooftop Solar Supply Curve

The rooftop solar supply curve is shown in Figure J - 7. A supply curve shows the amount of rooftop solar energy generation available in different levelized cost bins. For example, there is just under 500 aMW of commercial rooftop solar potential available for less than $100/MWh. For less than $160/MWh, there is 2,000 aMW of combined commercial and residential potential.

This supply curve is used in the Plan's resource optimization models, primarily OptGen, to compare the costs of other generating resources and conservation resources to these rooftop solar resources. For example, if the forecast shows a future need, and there are resources available at $50/MWh, the rooftop solar would not be competitive. However, if the competing resources are costing $120/MWh, then some residential and commercial rooftop solar (approximately 1,300 aMW) would be competitive[12].

[12] Levelized cost isn't the only factor for determining resources. The shape and ability to address other system attributes can also be factors.

Figure J - 7: Rooftop Solar Supply Curve

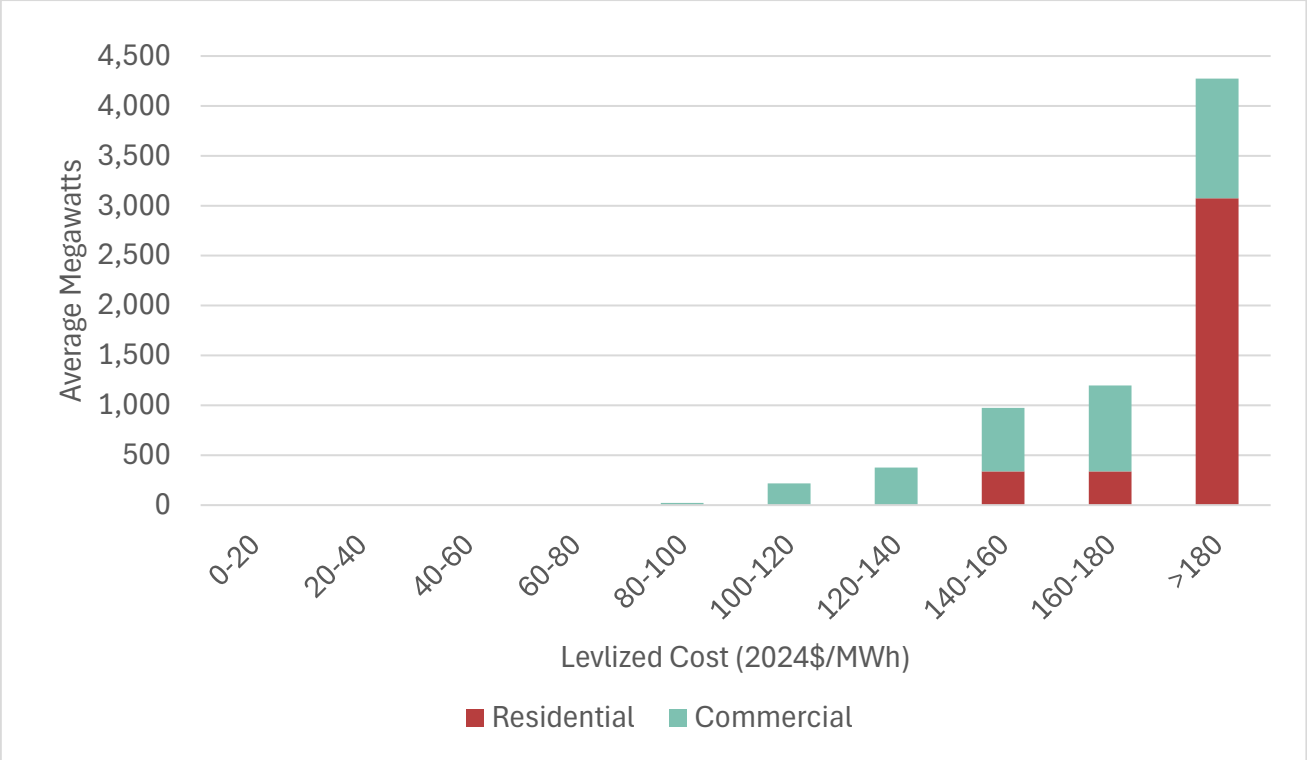
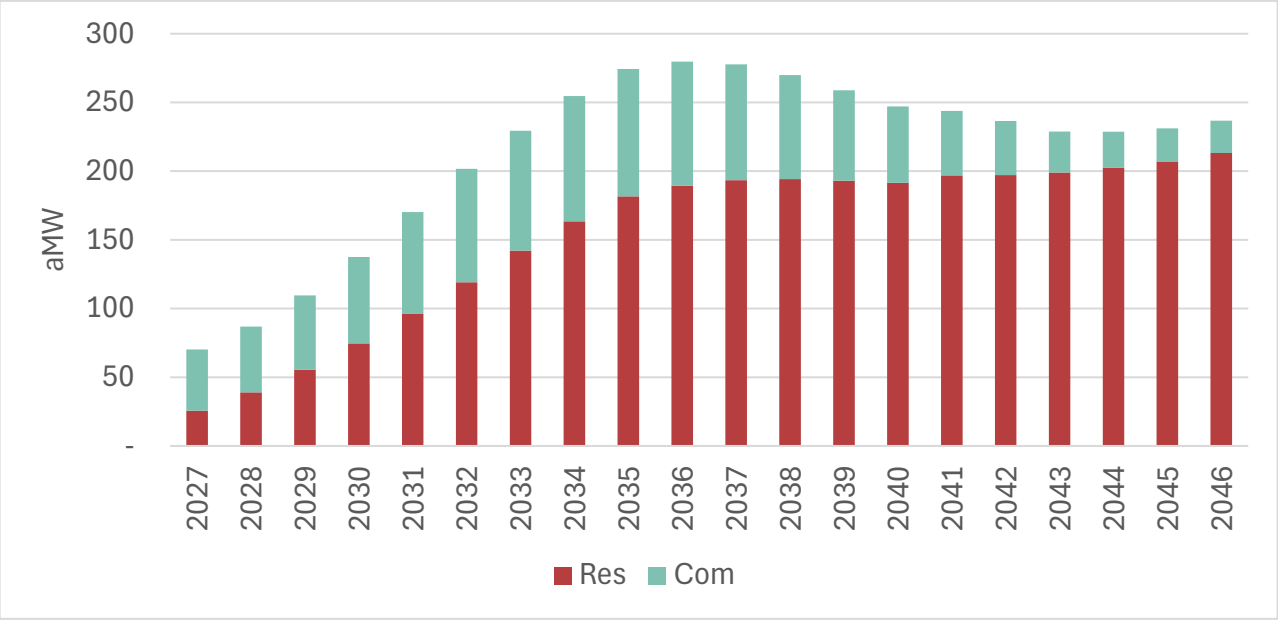


Figure J - 8 shows the annual incremental potential (aMW) which includes the ramp rates.

Figure J - 8: Rooftop Solar Annual Incremental Potential



Rooftop Solar Potential by Zone

Table J - 9 shows the total achievable potential in 2046 for the commercial and residential sectors by modeling zone. These modeling zones are used throughout the Ninth Plan.

Table J - 9: 20-year Achievable Potential (aMW) by Modeling Zone

Zone	Residential	Commercial	Total
AVA – Avista Utilities	248.54	58.30	306.84
BPA_IDMT – Bonneville Power Administration Idaho and Montana	104.93	83.32	188.25
BPA_OR – Bonneville Power Administration Oregon	175.04	66.36	241.40
BPA_WA – Bonneville Power Administration Washington	563.39	133.00	696.39
CCPUD – Chelan County PUD	20.77	7.22	27.99
DCPUD – Douglas County PUD	17.33	9.26	26.59
GCPUD – Grant County PUD	20.85	16.91	37.76
IPCO – Idaho Power Company	469.98	161.97	631.94
NWMT – NorthWestern Energy Montana	93.77	79.37	173.15
PACE – PacifiCorp, East	89.93	55.47	145.40
PACW – PacifiCorp, West	345.63	221.46	567.09
PGE – Portland General Electric	300.31	146.14	446.45
PSE_Central – Puget Sound Energy, Central	194.66	34.70	229.36
PSE_North – Puget Sound Energy, North	121.66	34.70	156.36
PSE_Olympia – Puget Sound Energy, Olympia	80.87	31.45	112.32
SCL – Seattle City Light	167.58	55.46	223.04
TPWER – Tacoma Power	59.32	3.45	62.77
Totals	**3074.57**	**1198.54**	**4273.11**

Adjusting for Load Futures and Scenarios

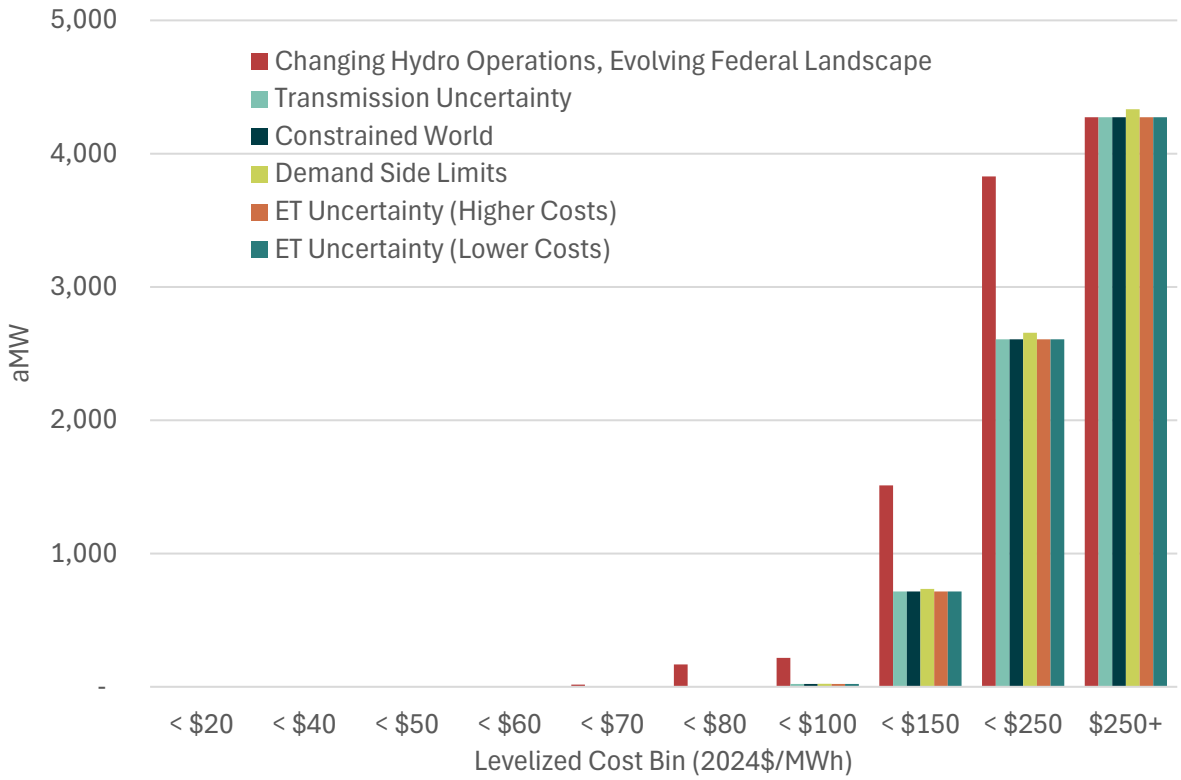
There is ultimately not a single set of rooftop solar supply curves for the Ninth Plan, but rather many variations, depending on the load future and analysis scenario being run in the model. Load futures and scenarios are similar in that they can both have changing assumptions that alter the shape, magnitude, and/or costs of the rooftop solar supply curves; however, they are different in that all load futures are present in every scenario, whereas each scenario is distinct from one another.

The sensitivities are designed to examine how rooftop solar, and other demand and supply side resources, may be selected differently depending on several different important factors, such as:

- whether or not federal tax incentives are available for rooftop solar
- whether rooftop solar is available according to the timeline assumed in the starting point

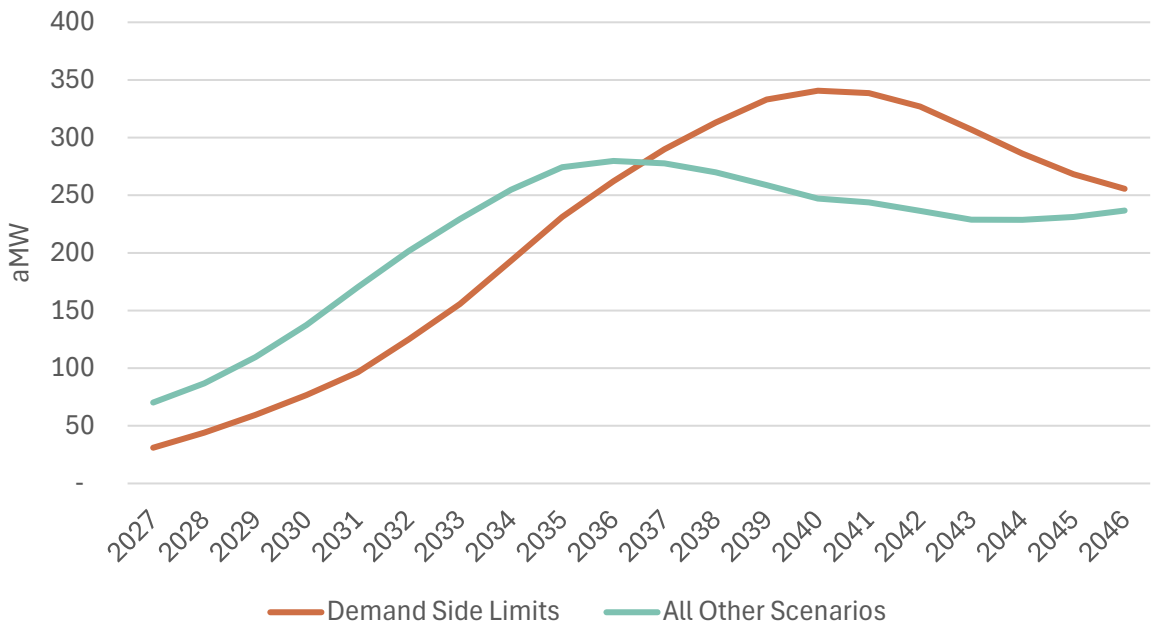
Tax credits are included in all sensitivities of the Changing Hydro Operations scenario and the Evolving Federal Landscape sensitivity of the New Resource and Transmission Risk scenario, but excluded in all others. Figure J - 9 shows the effect of including or excluding the tax credits on the rooftop solar supply curves.

Figure J - 9: Final Set of Supply Curves Used Across All Ninth Plan Sensitivities



The pace of adoption of rooftop solar was more limited in the Demand Side Resource Limitations scenario, which means that slower ramp rates were used relative to all other scenarios. Figure J - 10 shows the effect of the slower ramp rates on incremental available potential in the earlier years of the Plan period. Technical Appendix N – Scenario Modeling and Results provides more information on the specific assumptions in each scenario.

Figure J - 10: Annual Incremental Potential Across All Ninth Plan Sensitivities



Technical Appendix K: Modeling Framework

Contents

Discussion of Power System Model Scope 1
Resource Strategy Analysis 2
Focus of Modeling 2
General Discussion About Modeling in OptGen/SDDP 3
Testing Risk 8
Needs Assessment and Adequacy Check 15
Methodology for Checking for Adequacy 15
Temperature Sensitive Load Forecast 16
Wholesale Market Availability 20
Buildout Representation in Other Models 20
Further Reference 21

Discussion of Power System Model Scope

At a basic level, effective power system planning requires a deep understanding of how, why, and where power is created, transmitted and delivered. Understanding the costs and implications of the power system can require many specialized modeling techniques and methodological approaches, since the system is complex and all aspects can rarely be understood by using just one analytical approach as a lens. Adding to that complexity, the Northwest region is one part of the greater Western Interconnection, which spans three countries and is managed by a disparate group of entities.

Therefore, analyzing power system cost and risk requires an approach to modeling that is based on economic fundamentals. This involves evaluating generation costs, fuel availability, fuel pricing, and environmental impacts. It also requires accounting for the transmission system's capacity to deliver power across a broad footprint to meet fluctuating electric demand. Some aspects of the power system can be modeled in varying degrees of detail, based on available public information and time available to develop such an analysis. Similarly, some policies and operational realities affecting the power system are cross sectoral and not easily separable from the system impacts of other sectors. Due to all these nuances and more, the Ninth Power Plan's modeling approach splits this complex

problem into simpler problems that can be solved using analytical methodologies and computer modeling software.

The Council uses many models to support the analysis of the Ninth Plan. Each model is designed and configured to answer different questions about the power system. The Council uses three primary models to understand cost and risk tradeoffs associated with different resource portfolios representing the bulk power system for the greater West or inside the Northwest region:

1. OptGen coupled with SDDP is used for evaluating costs and risks associated with different regional strategies over many future power system environments.[1]
2. The GENESYS model is used to evaluate hourly system operations within the region and for resource adequacy.[2]
3. Aurora is used to evaluate hourly operations and market fundamentals across the Western grid.[3]

The high-level flow of how the Council uses these three models in its analysis is represented in the Introduction section of the Technical Appendix N – Scenario Modeling and Results.

Resource Strategy Analysis

Focus of Modeling

The primary goal of power system analytics supporting resource strategy selection is to understand the implications of costs and risks (tail-end costs, undesirable outcomes, etc.) of investments in portfolios containing new resources and reserves. For a model to be able to estimate total costs, it needs to be able to calculate the investment costs of a set of resources and reserves, the production costs of those and existing system resources and reserves, and any additional costs such as those related to public policies or regulations that are not already included within the production costs.

Capital expansion models seek to minimize total costs by simulating investment in a set of resource/reserve solutions that meet a set of obligations (load, adequacy, policies, etc.) over a certain period of time. The fixed cost (capital and fixed operations and maintenance) of a set of resources is one piece of the overall objective to be minimized. Production costs and other costs are also needed to determine if the investment is least cost. A production cost model or module of a capital expansion model simulates how a new set of resources/reserves fits into the existing power system by minimizing the variable cost of production required to meet electric demand and other obligations. This includes any costs associated with the production of power such as fuel costs, variable costs

[1] OptGen and SDDP are commercial products licensed from PSR. See https://www.psr-inc.com/en/software/ for more details.
[2] GENESYS was codeveloped by Council staff with EPIS (now Energy Exemplar) and PSR and is maintained by PSR.
[3] AURORA is a commercial production cost model licensed from Energy Exemplar.

associated with policy compliance, costs to transmit the power from one place to another, and variable operations and maintenance costs.

Sometimes production-cost modeling can be very detailed, like understanding the uncertainties and costs of fueling generating resources or providing operational level of detail like the co-optimization of providing generation and holding reserves. Additionally, the complexity of these problems can grow as the duration and fidelity of the problem being optimized increases, resource types and attributes are modeled in more detail, and the topology of the problem grows in complexity and size.

Over time, these problems have grown in complexity to necessitate the problem being split into parts. The Council's methodology has been to separate the parts into a wholesale market study (outside the region capital expansion and production cost modeling), a needs assessment (within region production cost modeling that focuses on identifying the existing power system's needs given increasing obligations), and a resource strategy analysis (regional capital expansion and production cost modeling that identifies the least cost/risk strategy to meet regional obligations over time).

General Discussion About Modeling in OptGen/SDDP

OptGen is a long-term expansion planning model that determines the least-cost sizing and timing decisions for construction, retirement, and reinforcement of generation capacities, transmission network, and natural gas pipelines. OptGen calls on SDDP, a production-cost model, to determine the variable costs associated with a particular investment strategy. OptGen seeks to minimize costs by making particular investments to meet growing system obligations and co-optimizing simulated power plant operations considering both energy and reserve requirements.

Due to the complexity of this analysis, OptGen and SDDP employ mixed integer programming methods to solve this cost minimization. Mixed integer programming (MIP) is a mathematical optimization technique that minimizes or maximizes an objective function within constraints involving a mix of different decision variable types including: continuous variables (i.e. size of transmission flows), discrete variables (i.e. number of new thermal plants in which to invest), and binary variables (i.e. unit commitment of certain power plants). Another feature of mixed integer programming is that optimality cannot be guaranteed "exactly," but within a particular range (gap) from the optimal linear solution.[4] For the Ninth Plan, and due to time and feasibility constraints, OptGen was set to stop attempting to solve the problem at a 3 percent gap.

Resource Parameters

Resources that are part of the existing system and candidate new resources are specified in SDDP via operational parameters and constraints. A candidate resource must be specified in SDDP to be available for selection in OptGen. Resource investment parameters are specified in OptGen. All

[4] The optimal linear solution in this case is the solution with all the non-linear constraints relaxed to make the problem linear which is generally much easier to solve.

generation and storage resources are defined to be in an electric bus along with different demands. All transmission resources are defined in SDDP to connect different electric buses and reserve sharing areas and new transmission resources can be selected in OptGen. Not all new resource types modeled necessarily fit into an explicitly defined resource in SDDP, so their operations are emulated by modeling them as similar resources.

For all resources, OptGen can specify the following: investment cost, fixed and variable operations and maintenance (O&M) costs, capacity, firm energy/capacity contribution, construction schedules, retirement/decommissioning options, environmental characteristics (emissions, clean-energy certificates, etc.), resource relationships, and more.

Resources Modeled as Hydro Resources

For resources represented as hydro generation resources, SDDP can specify the following parameters: minimum and maximum reservoir volumes, reservoir bathymetry, project spill and generation capabilities, turbine efficiency, water travel time and routing between cascading reservoirs, minimum and maximum outflows, spills, and reservoir volumes, initial reservoir contents, irrigation and flood control requirements, plant discharge and ramp rates, maintenance schedule and capability to provide reserves. The existing regional hydropower system has parameters that are often changing per the history described in Technical Appendix B – Existing System Parameters and Policies. Hydro generation resource operations constraints, with the exception of what is defined by the sensitivities described in Technical Appendix N – Scenario Modeling and Results, are defined through discussions with regional utility planners, hydro operators, and technical documents including the Water Management Plan and license documents.[5] Due to the need to account for reservoir/storage/fuel inventory constraints, in addition to the existing hydropower system, certain candidate new resources are modeled as hydro resources. These include clean long-duration storage and clean mid-duration storage/peaker.[6] Please see Technical Appendix G – New Generating Resources for more information on these proxy resources.

Resources Modeled as Thermal Resources

For resources represented as thermal generation, SDDP can specify the following parameters: fuel consumption constraints, efficiency curves, variable operations and maintenance cost, minimum and maximum generation levels, ramp rates, unit commitment parameters (startup costs, minimum up and down times, etc.), forced outage rate, maintenance schedule, and capability to provide reserves. Thermal unit commitment constraints are primarily utilized for in region dispatch of existing and new plants (specifically, larger combined cycle gas turbines and coal plants) whereas outside the region

[5] For a more complete list of the documentation please follow up with Council staff.

[6] In SDDP, the longest cycle contemplated by the model for storage resources is 24 hours which does not capture the possibility for longer cycles that are some of the defining attributes of longer duration storage resources whereas hydro inventories are evaluated on a year-long basis.

thermal resources are represented by resource bundles by efficiency and resource type.[7] The resources modeled as thermal resources in SDDP are: new and existing gas plants, existing coal plants, geothermal plants, nuclear plants, clean baseload resources, and dynamic voltage regulation.[8]

Resources Modeled as Renewable Resources

For resources represented as renewable generation resources, SDDP can specify the following parameters: availability shape, variable operations and maintenance cost, minimum and maximum generation levels, maintenance schedule and curtailment cost.[9] Existing and new in-region resources are represented as individual resources. Outside the region renewable resources are represented by resource bundles by availability and resource type. The resources modeled as renewable resources in SDDP are as follows: stand-alone solar, the solar part of a solar hybrid,[10] and onshore and offshore wind generators.

Resources Modeled as Storage Resources

For resources represented as storage resources, SDDP can specify the following parameters: charge/discharge efficiency, minimum and maximum storage, initial storage, variable operations and maintenance cost, minimum and maximum generation levels, maintenance schedule and capability to provide reserves. The resources represented as storage resources in SDDP are stand-alone short-duration storage, the battery part of the solar hybrid, and pumped storage plants.

The costs and attributes of all new generating and storage resources parameters are described in more detail in Technical Appendix G – New Generating Resources. Technical Appendix B – Existing System Parameters and Policies provides more information on the existing system capabilities, both in region and across the West

Resources Modeled as Demand-Side Resources

For resources represented as energy efficiency resources, SDDP can specify the size and shape of the resources as load modifiers and associated with a particular demand segment. The Council used this resource type to model all the demand side resource bundles (conservation, demand response, and rooftop solar) aside from the voltage regulation. Further information on parameters for conservation and demand response resources is defined in Technical Appendix H – Conservation Methodology and

[7] This simplification helps improve computational speed without significant loss of fidelity as was discussed in the November 6, 2024 System Analysis Advisory Committee meeting.
[8] From an operational perspective, dynamic voltage regulation was modeled using the potential and treating that potential reduction in demand as a non-emitting thermal generator.
[9] Curtailment of a renewable generation is when a renewable generator could generate more power, but, often for transmission or operational constraints, chooses to dispatch down to a level of generation that can be handled by the grid. These costs can include wear and tear costs for curtailment or foregone revenue from Renewable Energy Credits.
[10] Solar hybrid resources were modeled as a stand-alone solar plant and battery must be associated when acquired.

Potential, Technical Appendix I – Demand Response Methodology and Potential, and Technical Appendix J – Rooftop Solar Methodology and Potential.

Zonal Transmission Topology

Ninth Power Plan SDDP modeling clusters resources and demands associated with specific utility service areas (or subsets of the service areas) across the west into buses. These areas are connected to each other in the model via transmission paths (the Ninth Plan does not model transmission inside of buses). This representation of buses and transmission lines is called a transport model. It is an abstraction of the actual electric transmission topology into a representation that can be solved at a tractable granularity as opposed to a power flow model which more accurately represents the system but is currently too computationally intensive to use while also solving the investment problem.

In addition to the assignment of loads and resources to buses, those buses and subsets of the demands and resources are assigned to reserve sharing groups. The assignment of buses to reserve sharing groups is similar to the participation of utilities in planning reserve pools. For the Ninth Power Plan the Western Power Pool is split into two reserve sharing groups: the northwest region and the mountain west region. This is done for consistency with interpretation in other models. These reserve sharing groups are assumed in SDDP to share planning reserves, balancing reserves, and contingency reserves. Per the discussion in Technical Appendix L – Wholesale Market Availability Results, this pool and bus representation is a simplification that reflects the uncertainty around the changing market landscape of the Western Electricity Coordinating Council (WECC). Along the same lines, the net import capability into the pool representing the Northwest was limited to the seasonal limits from the needs assessment per Technical Appendix M – Needs Assessment Results.

Plant dispatch and reserve assignment are simulated for 35 load-resource buses and 5 pools as specified in Table K - 1 which comprise the SDDP representation of the WECC.

Table K - 1: OptGen/SDDP Topology

Pools	Zones
Western Power Pool (inside the region)	17 buses - Pacificorp (West and East Idaho), Portland General Electric, Bonneville Power Administration (Oregon, Washington, Idaho/Montana), Northwestern, Avista, Tacoma Power, Seattle City Light, Puget Sound Energy (North, Central, and Olympia), Idaho Power, Chelan County PUD, Douglas County PUD and Grant County PUD

Pools	Zones
Western Power Pool (outside the region)	9 buses – Pacificorp East (Wyoming and Utah), Public Service Colorado, Nevada Power (North and South), Western Area Power Administration (Upper Missouri, Colorado, Wyoming), New Mexico[11]
California Independent System Operator	6 buses – Northern California[12], Southern California[13], Imperial Irrigation District, San Diego Gas and Electric, LADWP, and Baja California
Southwest Power Pool	1 bus - Arizona[14]
Canada	2 buses - BC Hydro, Alberta Electric System Operator

Electric transmission between these buses is limited by the rated transport capability between the buses. The ratings are a representation of the capability of large transmission infrastructure connecting the buses, with the exception of the Northwest region which has an additional seasonal net import limitation in and out of that pool as described above. A history of the existing transmission and description of new transmission assumptions are described in more detail in Technical Appendix B – Existing System Parameters and Policies. Transmission lines in the model, which as described above are an interpretation of actual transmission infrastructure, can be defined by the capability of transmitting power in either direction between buses, directional wheeling rates between buses, directional loss factors between buses, and at times seasonal availability.

Regional Versus Outside the Region Modeling

As alluded to above, the regional resources, transmission, and loads are modeled in greater detail than outside the region resources, transmission, and loads. This is due to a few factors: the availability and granularity of public information outside the region, the primary scope of Council staff on in-region concerns, and computation simplifications that allow for speedier OptGen/SDDP simulation time that enables for more complexity elsewhere. In particular, some simplifications of note are as follows: the bundles of outside the region resources by attribute and type, bundles of outside the region demands into one demand per bus, and simplifications of the topology by clustering some out-of-region utilities into larger buses.

[11] Public Service New Mexico and El Paso Electric are combined in this representation.
[12] Pacific Gas and Electric (North, Bay Area and Path 26) and Balancing Area of Northern California are combined in this representation.
[13] Southern Cal Edison and VEA are included in this representation.
[14] Arizona Public Service, Salt River Project, Tucson Electric, and Western Area Power Administration (WAPA) Lower Colorado Area are combined in this representation.

Policies

OptGen and SDDP modeling incorporates policies via many mechanisms including, but not limited to, energy targets, tax credits, and emissions pricing. Some policies require multiple model mechanisms to emulate the actual implementation of a policy. Some policies require simplification to best quantitatively enforce policy language that does not have a viable analogue in the modeling. Table K - 2 describes at a high-level the implementation of some of the major policies in the regional strategy modeling.

Table K - 2: Policy Implementation in OptGen/SDDP

Policy or Collection of Policies	OptGen Mechanism	SDDP Mechanism
WECC-wide aggregation of Zero Emissions Policies and Renewable Portfolio Standards	Annual firm energy minimums of zero emitting or renewable WECC resources as a percentage of WECC demand	Curtailment costs of WECC renewables and discretionary spill of northwest hydro linked to imputed zero emissions or renewable energy credit pricing[15]
Emissions Pricing in WA, CA and Canada	None	Emissions pricing on emitting units within and imputed emissions pricing on wheeling costs into the jurisdictions with pricing[16]
Clean Energy Transformation Act in WA	Annual firm energy minimums of zero emitting or renewable regional resources as a percentage of WECC demand[17]	None

The policies incorporated into plan work are described in more detail in Technical Appendix B – Existing System Parameters and Policies.

Testing Risk

The resource strategy analysis considers the costs and risks of many different future outcomes explicitly in the analysis. Modeling different future combinations of demand for electricity, natural gas

[15] Imputed pricing based on California carbon pricing when non-zero and only non-zero when the existing system requirements did not add up to the aggregate policy obligation.
[16] Imputed pricing based on the average emissions associated with an unspecified market purchase. The average emissions are calculated using an assumption that the product of the emissions rate of a combined cycle and the remainder of the load when netting the aggregate zero emissions obligation for the WECC with the WECC load divided by the WECC load.
[17] The penalty for violation of this soft constraint is set to the social cost of carbon.

prices and price volatility, and fuel availability for hydro, wind and solar generation for all scenarios and sensitivities explores the uncertainty around major power system fundamentals forecasts. Modeling scenarios and sensitivities explicitly explores specific concerns around the possible pace for new resource development, the cost of new resources, the future availability of transmission, and future hydropower operations. This allows the Council to better understand uncertainty in the cost and availability of tools to meet growing power system obligations in the long term. In addition, by holding both planning and operating reserves throughout all futures and scenarios/sensitivities, the modeling implicitly explores the operational risk required to maintain an adequate and economic system.

Futures

A future is defined as one particular realization of major uncertainties affecting the power system. In the Ninth Power Plan this is represented as a particular combination of forecasts for the demand for electricity, natural gas prices and price volatility, and fuel availability for hydro, wind and solar generation. One resource strategy likely has a different cost over each future. Minimizing the expected value of the costs over all the futures tested is used to determine the optimized strategy for a particular scenario and sensitivity.

History of Planning for Uncertainty

The history of the Council and the Power Act explicitly addresses the need to plan for uncertainty in demand. This is partly due to the outcome of Northwest power system planning practices in the 1960-70s that led to expensive resource decisions for the region (the decision to pursue multiple large nuclear projects in the Northwest, many of which were not finished and resulted in a large debt default).[18] In the Ninth Power Plan, five different demand forecast pathways were created to test the uncertainty in the underlying non-weather drivers of power demand. This is explored in more detail in Technical Appendix F – Electricity Demand Forecast. Additionally, each of those fundamental forecasts was represented for three different views of the future climate, as is explored in more detail in Technical Appendix D – Climate Model Data and Assumptions. These 15 demand futures represent the range of demand uncertainty explored explicitly in the resource strategy analysis. Temperature sensitive demand uncertainty is considered as well within the needs assessment modeling and implicitly is considered as part of the reserve margin to maintain adequacy.

Current Futures Methodology

Future uncertainty of electricity supply is explored through a couple different lenses: price and availability of the primary fuels used in the Northwest power system. Since the Council does not currently perform detailed fuel fundamentals modeling on natural gas, price is used as a proxy for understanding supply fundamentals uncertainty, whereas forecasts of wind speed and direction, solar irradiance, and hydro runoff throughout the region are used explicitly to understand the

[18] https://www.nwcouncil.org/reports/columbia-river-history/northwestpoweract/

fundamentals of the fuels of other major regional power sources. The Council uses one expected price forecast for coal, fuel oil, and other fuels. This is due to the lower penetration of those resource types in the region, and for coal lower historical price volatility, and thus the lessened fuel risk exposure.

Natural gas resources are often on the margin for the power system and thus affect the wholesale price of power. For natural gas in the Ninth Power Plan, uncertainty is represented via price pathways (three different trajectories, low, medium and high) and price volatility (10 different seasonal price multipliers). The forecasts and the methodology used to create them are discussed in detail in the Technical Appendix E – Thermal Fuels Forecast.

Forecasts of hydro runoff, solar irradiance, and wind speed/direction are built from same 30 years of climate data from the three different climate models used for the temperature sensitive loads. The development of these data are discussed in more detail in Technical Appendix D – Climate Model Data and Assumptions.

Representative Futures Sampling Methodology

If used in full, the futures discussed above would create 13,500 different combinations of outcomes. Some of those combinations of futures are very similar, and thus simulations of these futures might yield similar outcomes and create unnecessary simulation time and cost. A methodology using a linear program was used to determine a distributionally relevant representative sample of 10 combinations from the entire range of 13,500 future combinations for each of the seven years evaluated in the regional strategy analysis modeling.[19] Using a representative sample of futures ensures that any resource strategy would be subjected to a wide array of hydro conditions, prices, and demand which represent the highest up and downside risks for the region.

Scenarios

A scenario, or sensitivity, in power plans has been used to explore an area of risk not represented within the uncertainty explored by the futures. In recent plans, it has been exploring some of the biggest issues leading up to that plan, like policies or resource availability uncertainty. In the Ninth Plan, there is significant uncertainty around how the hydro system will be operated going forward and what resources and transmission will be available when, and at what cost. The specific scenario descriptions are explored in more detail in Technical Appendix N – Scenario Modeling and Results Draft.

Each scenario is made up of multiple sensitivities and in each of those sensitivities the same set of futures is explored in the years sampled (2028, 2030, 2032, 2034, 2038, 2042, and 2046). The capital expansion for each sensitivity is meant to inform resource selection from 2027 through 2046,

[19] Discussed during a OptGen Methodology Update: Clustering topic in a January 29, 2026 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-01-29.

however for this plan OptGen was run in snapshot expansions with some decisions locked from previous years as described in Table K - 3.

Table K - 3: Snapshot Years Description

Sample Year	Resource Decisions Locked	Available Resources	Other Details of Note
2028	Lock supply-side resources	Only planned supply-side resources and all demand-side resource	Limited supply-side resource availability due to overall resource ramping
2030	Lock demand-side resources	New wind, solar, hybrid and simple cycle gas generators available	Clean Energy Transformation Act in WA begins and additional planned transmission in region
2032	Lock supply and demand-side resources	New combined cycle gas generation and long duration energy storage (in most sensitivities)	End of action plan period of plan and additional transmission in region in some sensitivities.
2034		New pumped storage and geothermal	Additional transmission available in one sensitivity.
2038	Lock supply and demand-side resources		In most scenarios, WECC-wide zero emissions policies are binding in mid-2030's, Additional transmission available in some sensitivities.
2042		Mid-duration energy storage and clean baseload proxy resources	
2046	Lock supply and demand-side resources	Offshore wind	Many emissions policy resource targets increase in 2045

OptGen has two modes for running the model. The first allows for the production cost modeling and capital expansion modeling decisions to be co-optimized.[20] Running the model this way requires running a single year at the time. This method also ensures that balancing reserves for renewables are calculated dynamically, rather than iteratively. The second mode for Option is a full 20 year of investment decisions to be solved at the same time, requiring less fidelity on operations and an

[20] Called OptGen 2 in the PSR documentation.

iterative calculation of balancing reserves.[21] There were many discussions coming out of the 2021 Power Plan about cost-effective reserves required to support a resource strategy and thus, as an area of emphasis in this Power Plan, it was determined that it would be better to have a dynamic reserve determination. Therefore, the Council used the first approach for the Ninth Plan. This methodology of running snapshot years was discussed in more detail at the System Analysis Advisory Committee.[22]

Reserves

A reserve requirement in the resource strategy modeling represents any additional obligation over and above what is required for meeting the demand and policies. These reserves are held as an additional obligation and the resources holding those reserves cannot use that capability for meeting typical day load. This methodology in OptGen/SDDP incorporates the effect of holding reserves in terms of limiting market resource availability, where some of the available resource capability to meet typical day load are not available for economic exchange outside the particular reserve sharing pools. Those reserves are held collectively by appropriate resources in the same pool (defined in Table K - 1 above) and can be split into planning and operating reserves.

Planning Reserves

The planning reserves for the region contain a few interactive components: the reserve required to maintain enough resources to meet seasonal peak demand in a pool, and the reserve over and above the seasonal peak reserve, when necessary, needed to maintain adequacy and additional energy required to maintain adequacy. The calculation of the components of planning reserves is defined in detail in Technical Appendix M – Needs Assessment Results. The planning reserves philosophy for outside the region is discussed in more detail in Technical Appendix L – Wholesale Market Availability Results.

Seasonal Peaking Reserve Requirement

The seasonal peaking reserve is necessary because OptGen dispatches using typical days, in which a sample weekday and weekend day are sampled for the following 6 seasons: January/February, March/April, May/June, July/August/September, October/November, and December. The typical day weekday hour's demand is the average demand for that hour in the day for all weekdays in the season and similarly, typical day weekend hour's demand is the average demand for that hour in the day for all weekends in the season. Since it is important to ensure there are enough resources available to meet the demand in all the hours, including when loads are above average, a seasonal peaking reserve is specified that holds back an additional percentage over every hour's demand in a typical

[21] Called OptGen 1 in the PSR documentation.

[22] Discussed during a OptGen Methodology Update: Snapshot Years topic in a January 29, 2026 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-01-29.

day. The typical day methodology and logic was discussed in more detail in the System Analysis Advisory Committee.[23]

Additional Reserve Requirement for Adequacy

OptGen does not explicitly include the full suite of temperature sensitive loads and the interaction of all those loads with varying hydro and renewable conditions. These potential additional needs are calculated as an adequacy reserve margin over and above the seasonal peak reserve, and as an additional firm energy requirement for new resources, as defined in detail in Technical Appendix M – Needs Assessment Results. This reserve should account for situations not directly simulated in OptGen to ensure a resource strategy adheres to the Council's adequacy criteria.

Operating Reserve Requirements

OptGen holds operating reserves over and above the planning reserves to account for the uncertainty of supply delivery. For example, there may be forced outages on thermal or hydro generation (contingency reserves) or there will be uncertainty of the forecast of wind, solar, and small hydro generation (balancing reserves). The contingency reserves held are 6% of load in all hours.[24]

Dynamic Probabilistic Reserve Requirement

The balancing reserves are estimated via a methodology called dynamic probabilistic reserve (DPR) and are calculated based on the estimated reserves required to cover the forecast error of an entire pool's renewable generation.

Equation K - 1: Calculation of Dynamic Probabilistic Reserves

$$DPR = (1 - \lambda) * E[\Delta FE] + \lambda * CVaR_{1-\alpha}[\Delta FE]$$

The dynamic probabilistic reserves are defined in more detail in Equation K - 1. The variables in the equation are:

- λ is a risk aversion weight in %. This weight is set at λ=100 for the Ninth Power Plan putting all the weight on the tail end of the distributions of ΔFE.

[23] Discussed during the OptGen Methodology Updates topic in a January 29, 2026 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-01-29 and October 1, 2025 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-10-01.

[24] This is a proxy of the 3% load and 3% generation simplification of the reserve sharing rule Bal-002-WECC 3, https://www.nerc.com/globalassets/standards/reliability-standards/bal/bal-002-wecc-3.pdf.

- 1-α is a reliability level in %. Set at α =5 in the Ninth Power Plan, meaning the ΔFE protected against is the 95 percentile of all ΔFE.
- ΔFE is the difference between the forecast error in solar and wind generation from one hour to the next and the forecast error is defined as the difference between the forecast renewables in an hour in the typical day and the generation in that hour for any other future.

Due to the dynamic nature of this calculation, as the model adds renewable generation it also must add additional resources that hold the balancing reserves (or utilize more existing resources for reserves). One effect of this is higher value for renewable generation diversity because it lowers the reserve burden.

Reserves Summary

In summary, the planning reserves primarily account for uncertainty in forecasted demand represented in the typical day operations, and the operating reserves the uncertainty in the availability of resources to meet those demands. These reserves are significant portion of the obligations of the power system. By including these reserves into typical day operations, the modeling incorporates the resource signal to meet resource adequacy needs and also considers the effect of holding reserves as an important economic component of broader power system market fundamentals.

Resource Selection

In OptGen the model can select either supply or demand side resources to minimize costs in the objective function, and each of the resources has attributes that are useful for meeting system obligations and economics within the regional portfolio.

Focusing on the region economics defines when a resource may be least cost for meeting in region resources and also for exporting power to meet out-of-region loads. All resources can be acquired for economic purposes and can meet load when fuel is available. Some resources like storage and hydro can choose to save (in the case of hydro) or create (in the case of storage) fuel for other hours rather than meeting a need in the current hour. In some cases, specifically when interacting with Northwest hydro resources which are primarily fuel limited (rather than capacity limited), adding resources at a non-coincident time to need can free up fuel to serve peaking, reserves, spill, or other river system needs that are time dependent in later hours. This means that Northwest resource economics are best considered from a portfolio lens.

Additional regional obligations are primarily meeting reserves, policy, or non-power obligations on the hydro system. Resource types that can provide peaking, contingency or dynamic probabilistic reserves in OptGen are as follows: new and existing thermal, hydro, and storage. For a resource to get credit for providing peaking reserves it must have the capability available to hold the reserve and fuel to generate if the reserve was called upon. Resource types that can provide energy reserves in OptGen are as follows: conservation, new thermal, and new renewable generation. Resource types that can help meet public policies are described above in Table K - 2. Firm energy reserve provision is based on the expected fuel availability of the resource regardless of the obligation. Resource types that can reduce obligation burden in general are new energy efficiency and demand response as they

directly reduce the load driving peaking and energy reserve requirements, public policies, and reduce the obligation of regional hydro to serve the power grid.

Needs Assessment and Adequacy Check

One of the most important obligations considered in the resource strategy analysis is regional power system adequacy. The Council's regional adequacy methodology is a multiple metric probabilistic approach focusing on thresholds of frequency, magnitude, and duration of potential wholesale power system shortages that meet the expectations and criteria of regional planners as a reasonable cost versus risk tradeoff. The approach is probabilistic and the operational modeling includes additional risk factors not exogenously included in the resource strategy. Some of the additional risk factors modeled include multiple stage uncertainty and the realization of that uncertainty for load and renewable generation, hourly exploration of temperature sensitive load excursions with all 90 climatic hydro and renewable availability conditions, and more operational detail reflected in the modeling of the regional hydro system. This general approach is described in more detail in Technical Appendix M – Needs Assessment Results.

Since the modeling approach is complex and time consuming, the Council uses the GENESYS model separately from OptGen/SDDP to calculate a set of reserves that account for system needs and to check a resource strategy for adequacy once a candidate strategy has been adopted.[25]

Methodology for Checking for Adequacy

GENESYS and OptGen/SDDP are models with similar transmission topology and market setups. Unlike GENESYS, though, the resource strategy in OptGen/SDDP does not simulate the operations nearing stressful events. Instead OptGen/SDDP uses a reserve margin that is calculated via the needs assessment to send the signal for capacity and energy on a seasonal or annual basis. OptGen seeks to meet any needs by adding resources with attributes that add to reserve capability to meet the seasonal reserve margins but may not perfectly fit the need in some seasons. Since OptGen may also add resources for policies and broader economics, sometimes the system may be long in comparison to load and reserves in a particular season. Since the reserve margin from the needs assessment is simplified and imperfect method for translating all the fidelity of the operational record from GENESYS, it is not expected that the check will yield a system that exactly meets the thresholds of all the metrics. It is expected, however, that an adequate strategy will not violate any of the adequacy criteria.

In other words, when the candidate resource strategy is put into GENESYS, run with the same setup as a needs assessment but with the additional resources from the strategy, the system may be more than sufficient on some of the adequacy metrics. If the strategy does not check as adequate, then an iterative process is required to modify the portfolio selected to become adequate. As this iteration

[25] As described in the Additional Reserve Requirement for Adequacy section in this appendix above.

process can be timely and costly, when the adequacy criteria are developed into reserve margins the process of creating the reserve signal tends to err on the conservative side (i.e. err towards something that would incentivize slightly more than less resource additions).

Temperature Sensitive Load Forecast

In the Ninth Power Plan, the Itron load forecasting model was used to produce load forecasts for all 13 Northwest Balancing Authorities (BAs) for five pathways: High Growth, Low Growth, Mixed Bag, Early Growth and Late Growth.[26] The forecasts are calculated under the influence of temperatures from the three climate models selected for the Power Plan whose Global Climate Models (GCM) are CanESM2 (A), CCSM4 (C), and CNRM-CM5 (G).[27]

In the GCM data, each temperature year varies based on underlying trends and simulated weather. As a result, extreme temperatures vary in timing and severity each year. The temperature year of the climate model is used for the same year in the Itron load model. For example, temperature data for year 2031 from the three selected GCMs is used in Itron to produce the three years of hourly load forecasts for 2031. In addition to temperature effects, Itron also has calendar date effects of year 2031, which include the influences of weekdays, weekends, holidays, and months (which represent the seasons).

However, Power Plan test year 2031 could also be under the influence of other climate model years from the 30-year set, 2020 to 2049, of the three GCMs, for a total of 90 possible climate model years. For the capital expansion model (SDDP/OptGen), only the Itron load forecasts were directly used. But to determine system needs, which are used to define reserves input to the capital expansion model, the full set of 90 possible weather years are used. Since needs and adequacy were primarily checked for year 2031 in the Ninth Plan, these additional forecasts were created for that year.

While Itron could be used to generate all 90 forecasts, this would be a lengthy endeavor. To save time, a simpler and faster regression model was developed to produce load forecasts based on the Itron model results. More specifically, the regression model was developed to reproduce the temperature-sensitive portion of the Itron load forecasts which mainly comprises the residential, commercial and industrial (RCI) loads. Among the five load pathways, the High Growth and the Late Growth share the same Itron RCI load forecasts; similarly, the Mixed Bag and Early Growth also share the same RCI load forecasts. Resultingly, the regression model is developed for only three pathways: High Growth, Low Growth, and Mixed Bag. To develop the regression model for the Itron RCI load forecast, the Council decided to adopt the Multivariate Adaptive Regression Spline (MARS) statistical algorithm.[28]

As an example, for Power Plan year 2031, Itron produces three years of hourly load forecasts using data from climate model year 2031 of the three climate models, A, C, and G. However, the hourly load

[26] See Technical Appendix F – Electricity Demand Forecast for more details.
[27] See Technical Appendix D – Climate Model Data and Assumptions for more details on climate scenarios A, C and G.
[28] See https://bradleyboehmke.github.io/HOML/mars.html for details of MARS implementation in R.

data set (consisting of three years) is too small to train the MARS model to fit Itron's hourly load shapes (i.e., simulate hourly loads for different types of days, for example, winter days and summer days). For simplicity, the MARS model was developed on three years of ITRON *daily average* (RCI) loads, totaling $(3 \times 365) = 1{,}095$ data points.

To describe development of MARS in more detail, let $i \in (1, 2, \cdots, 365)$ be the index of a day of year 2031 and $j \in (0, 1, \cdots, 23)$ be the index of an hour of a day. Furthermore, let the ITRON *daily average* load of day i be represented by $\bar{L}_i$, and the ITRON hourly load for hour j of day i be represented by L_{ij}, and let r_{ij} be defined as the ratio $r_{ij} = L_{ij}/\bar{L}_i$. Therefore, the output of the MARS model is the *daily average* load forecast $\bar{L}'_i$ for day i which then could be used to calculate the 24-hourly load forecasts of day i as $L'_{ij} = r_{ij} \times \bar{L}'_i$.

The ITRON daily input and output data represented in Table K - 4 below are used to develop (i.e., train) the MARS model:

Table K - 4: Types of ITRON Data for The MARS Model

GCM	Day Index i	Month	Day of Week	Holiday	Daily Avg. Temp.	Daily Avg. Load
A	1	1	Wed	Y	$T_{A,1}$	$\bar{L}_{A,1}$
A	2	1	Thu	N	$T_{A,2}$	$\bar{L}_{A,2}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
A	365	12	Wed	Y	$T_{A,365}$	$\bar{L}_{A,365}$
C	1	1	Wed	Y	$T_{C,1}$	$\bar{L}_{C,1}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
C	365	12	Wed	Y	$T_{C,365}$	$\bar{L}_{C,365}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
G	1	1	Wed	Y	$T_{G,1}$	$\bar{L}_{G,1}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
G	365	12	Wed	Y	$T_{G,365}$	$\bar{L}_{G,365}$

In Table K - 4, the first column GCM lists the GCM (A, C, or G) of the row of the Itron data.

The second column Day Index i lists the index of the day of a year. For example, the index of January 1st is $i = 1$; the index of January 2nd is $i = 2$; and the index of December 31st (of the non-leap year 2031) is $i = 365$.

In addition, the third column Month lists the month corresponding to day i, and the fourth column Day of Week lists the weekday of the day i, which for January 1st, 2031, is a Wednesday.

Also, the fifth column Holiday lists Y (representing Yes) if day i is a holiday and N (representing No) if day i is not a holiday. For example, day $i = 1$ corresponds to January 1st, New Year's Day, which is a

holiday, and therefore is listed as Y. On the other hand, day $i = 2$ corresponds to January 2nd, which is not a holiday, and thus is listed as N. Finally, day $i = 365$ corresponds to December 31st, New Year's Eve, which is considered as a holiday in Itron, and thus listed as Y.

The last two columns are the climate model daily average temperature and the daily average load of day i (an Itron model output), respectively.

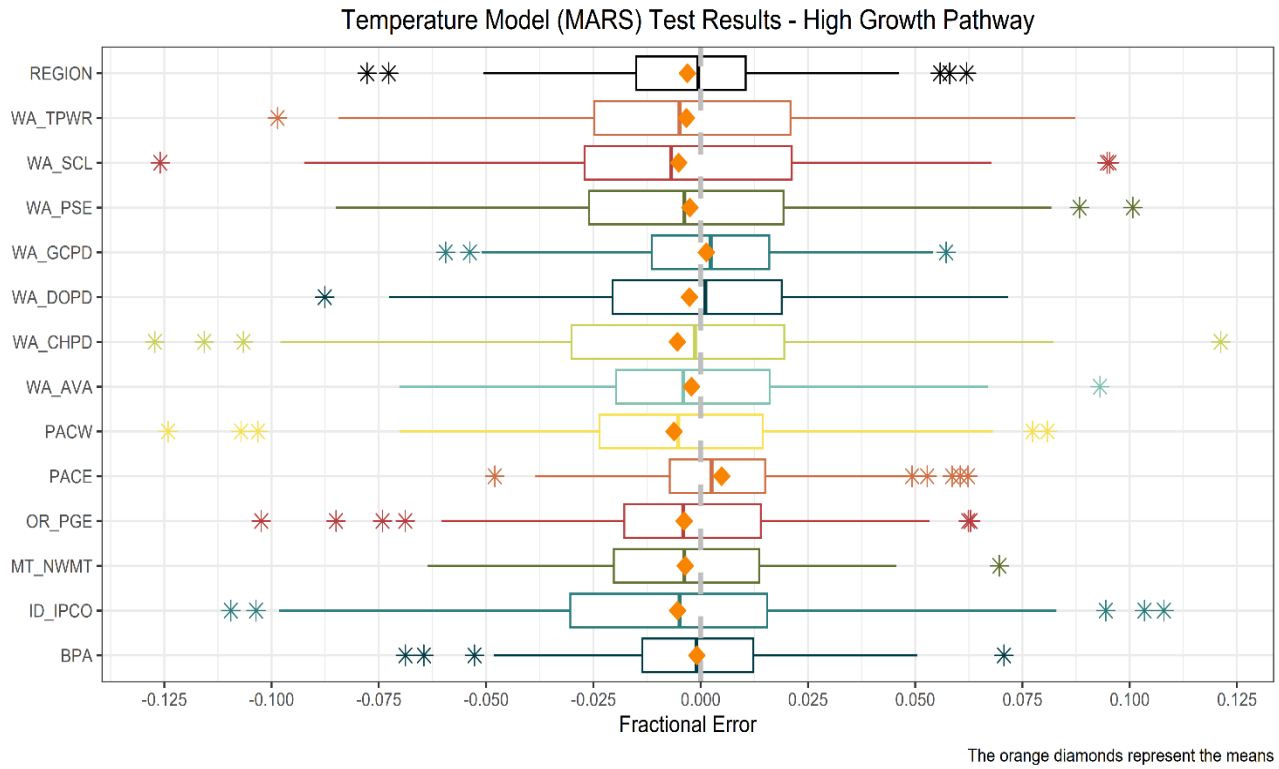
Itron data in columns Month, Day of Week, Holiday, Daily Average Temperature and Daily Average Load are used to develop the MARS model. In data science jargon, Month, Day of Week, Holiday, Daily Average Temperature are the predictors, and Daily Average Load is the target.

In developing the MARS model, following standard practice, the Itron data for year 2031 in Table K - 4 is divided into a training data set which is used to calculate an optimized set of parameters for which a representative error of the MARS load forecast is minimized with respect to the Itron load forecasts.

With the optimized parameters calculated, the MARS model is then evaluated on the test data set which is the remaining data in Table K - 4 after the training set has been removed. Typically, around 80% of the total data goes to training, and the remaining 20% is reserved for the test data set. The MARS optimized parameters were calculated only from the training set and not from the test set, so the test forecast error should be more likely to represent errors of the MARS model forecast when MARS is applied to relevant predictor data from other climate model years.

For Power Plan year 2031, a MARS model is developed for each of the 13 BAs for all three relevant pathways, High Growth, Low Growth, and Mixed Bag, using input and output training data from Itron. The MARS forecast errors of the test data set for the High Growth Pathway for the 13 BAs and the entire region (whose load is the sum of all 13 BA loads) are plotted below in Figure K - 1.

Figure K - 1: MARS Model Test Data Forecast Error for the 13 BAs and the Region



In Figure K - 1, the test data forecast errors for day i in the test data set is defined as a fractional error $E_i = (\bar{L}'_i - \bar{L}_i)/\bar{L}_i$ where $\bar{L}'_i$ and $\bar{L}_i$ are the MARS forecast and the Itron forecast, respectively. Therefore, a fractional error $E_i = 0.01$ means that for day i, the MARS forecast over-predicts the Itron forecast by 1%.

In more detail, the distributions of the test data daily forecast (fractional) errors for the 13 BAs and the region are plotted as horizontal boxplots where the orange diamond inside each boxplot represents the average. Furthermore, for each BA and the region, its boxplot (the box, the whiskers and the outliers) represents a distribution of 108 test data forecast errors.

In Figure K - 1, the BAs are listed along the y-axis, in alphabetical order starting at the bottom, and the fractional error E_i is plotted along the x-axis. [29] In addition, the vertical gray dashed line represents $E_i = 0$, and helps to visualize any positive or negative bias of the boxplots. For example, if the boxplot is biased to the left of the gray dashed line, then the MARS forecasts tend to under-predict the ITRON forecast. It could be seen that for 10 BAs and the region the MARS forecast tends to slightly under-predict the Itron forecast.

[29] The 13 Balancing Authorities (BAs) and their corresponding acronyms are listed in Technical Appendix I – Demand Response Methodology and Potential.

The largest errors are those outliers (plotted as $*$s) with magnitudes at about 12.5%. However, there are only four such large outlier errors from three BAs: Seattle City Light (WA_SCL), Chelan PUD (WA_CHPD) and PacifiCorp West (PACW). Furthermore, for all 13 BAs and the region, there is a total of only 14 outliers (out of a total $14 \times 108 = 1{,}512$ test forecast errors) with magnitudes above 10%, and the bulk of their distributions (i.e., the box and both whiskers) have magnitudes below 10%. In particular, for BPA (plotted at the bottom) which has the highest load magnitude and the entire region (plotted at the top), their forecast error distributions have magnitudes below 7.5%, with all whisker magnitudes around 5%.

The MARS models were also developed for the two remaining pathways, Low Growth and Mixed Bag. The model forecast errors have similar distributions as those plotted in Figure K - 1 in that there are few outliers with magnitudes above 10% with the bulk of the distributions being below 10%.[30] Therefore, the MARS models could be considered as being acceptable in reproducing the Itron RCI daily average loads for climate model year 2031 of A, C and G. The models are then applied to relevant predictor data from the 29 remaining climate model years of A, C, and G to forecast their RCI loads.

Wholesale Market Availability

While OptGen evaluates outside the region resources and loads in its regional resource strategy evaluation, the buildout of outside the region market resources is performed in Aurora. Since OptGen and GENESYS can dispatch and evaluate the resources outside the region in more detail than Aurora with respect to operating reserves, the Council uses the buildout of resources (rather than market prices) from the Aurora analysis. The goal is to better capture market fundamentals in the regional resource selection, the needs assessment, and the adequacy check. The buildout parameters and results in Aurora are described in more detail in Technical Appendix L – Wholesale Market Availability Results.

Buildout Representation in Other Models

The buildout in Aurora includes the buildout of regional resources. Those resources are removed from available market in SDDP/OptGen and GENESYS. Out of region resources built by Aurora are aggregated into bundles for modeling simplicity and speed when used in OptGen/SDDP and GENESYS. All resources are represented as bundles by resource type and zone. Existing thermal resources are bundled by heat rate and fuel type for each bus. New thermal resource bundles are by resource type (combined cycle gas turbines, simple cycle gas turbines, geothermal and clean baseload proxy resource). New combined cycle gas turbine (CCCT) resource bundles must be committed to the minimum generation of the smallest resource in the bin to be accessible for

[30] There is one exception: for the Mixed Bag pathway, the MARS model for Idaho Power (ID_IDPO) has a lower whisker *just slightly* below -10%.

generation or reserves in OptGen/SDDP and GENESYS dispatch. Unit commitment is inactive for existing out-of-region CCCTs and simple cycle gas turbines. Existing and new renewable resources are aggregated by renewable availability, type and bus. Existing and new storage resources are aggregated by type and bus. Existing out of region hydro is bundled by bus and modeled with simple inventory management and capability with the exception of British Columbia hydro in the Columbia River watershed which are modeled individually and with similar detail to in-region hydro resources. The outside the region existing hydro availability is described in more detail in the Technical Appendix D – Climate Model Data and Assumptions.

Further Reference

For more information pertaining to the public process of vetting the assumptions and methodologies in this technical appendix please reference the following meetings:

- **November 6, 2024 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2024-11-06
- **February 27, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/resource-adequacy-and-system-analysis-advisory-committees-combined-meeting-2025-02-27
- **April 1, 2025 Council Meeting:** https://www.nwcouncil.org/fs/19331/2025_04_07.pdf
- **July 17, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-07-17
- **August 26, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-08-26
- **October 1, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-10-01
- **November 5, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-11-05
- **January 6, 2026 Council Meeting:** https://www.nwcouncil.org/fs/19713/2026_01_3.pdf#page=8
- **February 26, 2026 Council Meeting:** https://www.nwcouncil.org/fs/19748/2026_02_7.pdf
- **April 26, 2026 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-04-22
- **May 6, 2026 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-05-06

Technical Appendix L: Wholesale Market Availability Results

Contents

Introduction 1
Modeling Methodology 2
Modeling Topology and Parameters 2
In Region Load Forecast 4
Out-Of-Region Load Forecast 4
Gas Price Forecast 5
Renewable and Hydro Generation Availability Forecasts 5
Modeling Setup 6
Modeling Results 6
Summary 6
Simulation Descriptions 7
Buildout Summary by Fuel Type 8
Further Reference 20

Introduction

The wholesale market availability of electricity is a key driver in resource decision making and captures the dynamics of supply of and demand for electricity throughout the Western power grid (the Western Electricity Coordinating Council (WECC) footprint).[1] To forecast market availability from 2027-2046 the Council has used a model, AURORA,[2] that can both estimate the buildout of future

[1] The Western Electric Coordinating Council is the not for profit corporation that exists to ensure a reliable bulk power system throughout the Western Interconnection, which includes the following: British Columbia, Alberta, Washington, Oregon, Idaho, Wyoming, California, Nevada, Utah, Arizona; most of New Mexico, Montana, Colorado; and some of the Dakotas, Nebraska and North Baja California.
[2] AURORA is a commercial production cost model licensed from Energy Exemplar.

resources throughout the Western grid and generate wholesale power prices via production cost modeling.

For the Ninth Power Plan, the Council's wholesale market availability forecasts are primarily focused on capturing the effects on wholesale market supply due to uncertainty about resource and transmission costs and availability. Multiple forecasts were used to align assumptions between the WECC-wide wholesale market availability analysis and the regional resource strategy analysis.

The first section discusses the scope and methodological setup of the WECC-wide capital expansion modeling studies, and the second section discusses the associated analytical results. The method for how the market availability study results are used to support the analysis using the Council's other models, OptGen/SDDP and GENESYS[3] is described in more detail in Technical Appendix K – Modeling Framework.

Modeling Methodology

Modeling Topology and Parameters

The general purpose of the wholesale market availability is to use the fundamentals of supply and demand to determine how much market resource is available during the plan horizon (2027 through 2046). The AURORA software is used to perform the capital expansion required to meet the obligations of the west-wide power system (demand, reserves, and policy obligations). The existing system and policies throughout the west are established as described in Technical Appendix B – Existing System and Policies. The capital expansion in AURORA is an investment module that adds to the existing system by building new generating or storage resources, as discussed in Technical Appendix G – New Generating Resources, to minimize total costs throughout the WECC over 20 years. The expansion can include builds for economics and to meet the following obligations: planning and operating reserve margins by operating pool, and annual zero emissions and renewable energy policy targets.

In addition to evaluating investment costs to meet obligations, AURORA also has a production cost modeling module. This is an economic dispatch model which means that electricity prices are based on the variable cost of the most expensive generating plant (marginal plant) or increment of load curtailment required for meeting load for each hour of the forecast period. The model co-optimizes the assignment of energy and reserves to minimize production cost. Capability is held back for both operating (contingency and balancing) reserves by pool or reserve sharing group, respectively.

Plant dispatch is simulated for 45 load-resource areas or zones specified in Table L - 1, which comprise the AURORA representation of the WECC.

[3] OptGen is a commercial capital expansion model and SDDP is a commercial production cost model that are licensed from PSR. GENESYS is a multi-stage production cost model co-developed by PSR and Council staff.

Table L - 1: Pools and Zones

Pools	Zones
Western Power Pool	27 zones - Pacificorp (West and East – Idaho, Wyoming and Utah), Western Area Power Administration (Upper Missouri, Colorado, Wyoming), Portland General Electric, Bonneville Power Administration (Oregon, Washington, Idaho/Montana), Northwestern, Avista, Tacoma Power, Seattle City Light, Puget Sound Energy (North, Central and Olympia), Public Service Colorado, Nevada Power (North and South), Idaho Power (Treasure Valley, Magic Valley and Far East), Chelan County PUD, Douglas County PUD and Grant County PUD
California Independent System Operator	10 zones - Pacific Gas and Electric (North, Bay Area and Path 26), Southern Cal Edison, Imperial Irrigation District, San Diego Gas and Electric, LADWP, Balancing Area of Northern California, VEA and Baja California
Southwest Power Pool	6 zones - Arizona Public Service, Salt River Project, Tucson Electric, Public Service New Mexico, El Paso Electric and Western Area Power Administration (WAPA) Lower Colorado Area
British Columbia	1 zone - BC Hydro
Alberta Electric System Operator	1 zone - Alberta Electric System Operator

The assignment of zones to reserve sharing groups is similar to the assignment of zones to planning reserve pools, but the Western Power Pool is split into two reserve sharing groups: the Northwest region and the Mountain West region for consistency with interpretation in other models. During the plan development many entities in the western grid are shifting from most entities being part of the Western Energy Imbalance Market (CAISO) and a few part of the Western Energy Imbalance Service (SPP) to a more even split of entities that have chosen to participate in the imbalance services associated with the upcoming day-ahead market structures, Enhanced Day Ahead Market (CAISO) and Markets Plus (SPP). Given that recent context, the current market modeling is more conservative with more balkanized reserve requirements and less reserve sharing than may happen in upcoming years' operations.

Similarly, while the regional capital expansion modeling can optimize while considering multiple pathways of demand, gas prices, forecast hydro runoff and renewable generation, the capital expansion in AURORA can only optimize over one deterministic set of forecasts given a set of existing system policies, parameters and retirements. Thus, not all estimates of demand, gas prices, forecast hydro and renewable generation were tested explicitly. A representative set of forecasts using the

aforementioned pool reserve margins accounting for uncertainty in these forecasts were developed in consultation with the Council's System Analysis Advisory Committee (SAAC).

In Region Load Forecast

In general, the representative demand forecast in the Northwest region was modeled using the P5: Mixed Bag demand forecast trajectory informed by the CanESM climate data (a mid-level forecast among the five tested throughout the rest of the plan) which was constructed as described in Technical Appendix F – Electricity Demand Forecast.

Out-Of-Region Load Forecast

The power system simulation models used in the Ninth Plan focus on the Northwest, but also simulate the broader Western Interconnection. Simulating this larger footprint is important since the Northwest is not a power island and interacts with the full interconnection. To run the models in a full Western setup, an out-of-region load forecast is required.

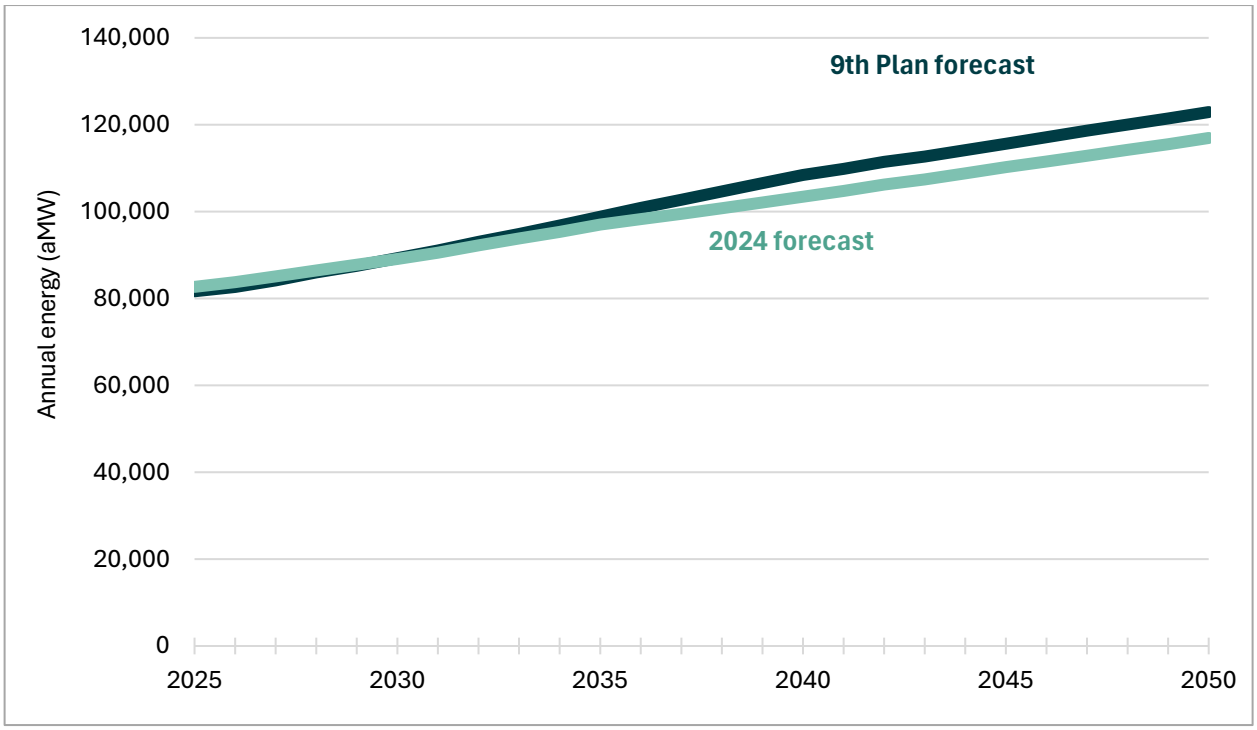
Unlike the Northwest load forecast, the out-of-region forecast is heavily reliant on other organizations' forecasts. It is a compilation of others' forecasts into a single forecast, as opposed to the Northwest forecast in regional strategy analysis in OptGen which includes different weather patterns and different load pathways, described in more detail in Technical Appendix K – Modeling Framework for each out-of-region zone. The main data sources used to create the out-of-region forecasts are:

- Utility integrated resource plans (and other utility level planning documents)
- The California Energy Commission Integrated Energy Policy Report
- FERC Form 714 data
- EIA Form 930 data

Much like the Northwest load forecast, the out-of-region load forecast has shifted upward in recent years (the forecast is refreshed every year or two for the adequacy study). The load drivers in the greater West are like those in the Northwest: data centers, electric vehicles, and general electrification. One interesting observation from the most recent California load forecast is that winter peak loads are growing significantly throughout the forecast period due to electrification.

Figure L - 1, below, shows the Ninth Plan's out-of-region load forecast compared to the forecast used in 2024 for the 2029 Adequacy Assessment. Note that this does not include Northwest loads (which as of 2026 account for roughly 20% of the West, on an annual energy basis). For annual energy the Ninth Plan's out-of-region load forecast averages 1.6 percent growth per year. These loads are assumed to include the impact of new demand-side resources (which is different than the frozen-efficiency load forecast developed for Northwest loads).

Figure L - 1: Ninth Plan Out-of-Region Load Forecast (does not include NW)



The out-of-region load forecast has an impact on model market fundamentals on many levels. First, it is the demand the models see and dispatch resources to meet. Second, it influences the resource buildout since it is used in the Western Interconnection capital expansion modeling. Thus, this forecast impacts the buildout, power prices, power flows, and the level of imports available for resource adequacy.

More discussion and detail on the out-of-region load forecast was shared at the April 2025 Council meeting, available here: https://www.nwcouncil.org/calendar/council-meeting-2025-04-08.

Gas Price Forecast

The gas price forecast utilized for the market availability study was the mid-level gas price forecast per the Technical Appendix E – Fuels Forecast.

Renewable and Hydro Generation Availability Forecasts

The renewable availability forecasts were developed per expected shapes from historical climate data outside the region and climate change informed data, using the CanESM model, inside the region as described in Technical Appendix D – Climate Model Data and Assumptions and Technical Appendix G – New Generating Resources. Similarly, the hydro runoff forecasts were developed per expected shapes and constraints from PNNL GODEEP climate data outside the region and climate change informed data, using the CanESM model, inside the region, as described in Technical Appendix D – Climate Model Data and Assumptions. In addition, the Council's GENESYS model is used to develop maximum and minimum hourly operation constraints and monthly inventory for

hydropower on a zonal basis for consistency with Columbia River operations, since AURORA does not contain detailed water travel time and operations logic that reflect the limitations on generation and reserves for the hydro operations in the Pacific Northwest.

Modeling Setup

The capital expansion was run from 2026 – 2046 in two steps to better converge to a result within a reasonable planning timeline. After running the study chronologically through 24 hours a day and 365 days in a year, the model was taking too long to solve within plan timelines. Thus, a simplifying approximation of the hourly production costs was utilized to represent the variable costs in the overall cost minimization of both investment and production costs in the objective function.

This methodology of using a sample set of days to represent typical production cost behavior for the broader WECC was developed in consultation from the SAAC is as follows:

1. The capital expansion was performed twice with the minimized solution from the first study used to seed the second study.
2. In the first study, the capital expansion starts without an initial strategy seed, and the model calculates the investment to minimize total costs. In this study, production costs were simulated by performing the zonal dispatch of the WECC for 24 hours per month per year. The second Tuesday of every month was used as representative of all days in the month.
3. In the second study, the buildout from the initial long-term WECC buildout described in step 2 above is used as an initial seed for the a new study where the model seeks to modify the investment to minimize total costs, but the production costs were simulated by performing the zonal dispatch of the WECC for 48 hours per month per year. The first and third Tuesday of every month were used as representative of all the days in the month.
4. The buildout from the second study is considered to be the “optimized” buildout for a given sensitivity.

Each simulation supporting the wholesale market availability for a particular scenario/sensitivity was performed in this way.

Modeling Results

Summary

The investments in new generating resources stabilize wholesale prices throughout the WECC over time with a couple exceptions associated with emerging technology cost risk. By 2032, $58 to 59 billion[4] in capital investment per year is required to meet obligations. By 2046, $81 to 89 billion in

[4] All costs and prices in this section are listed in 2024 dollars.

capital investment per year is required to stabilize wholesale prices. Annual average prices over all zones range from $33 to 37 per megawatt-hour in the beginning of the study, and by the end of the study range between $18 to 60 per megawatt-hour on average across the sensitivities. Nameplate investment for the whole WECC ranged from 265 to 287 gigawatts by 2046 over all sensitivities to meet just over 50 average gigawatts of expected demand growth throughout the WECC.

Simulation Descriptions

The plan scenarios and underlying assumptions are described in more detail in Technical Appendix N – Scenario Modeling and Results. The perspectives of certain wholesale market availability sometimes support one or multiple sensitivities for the overall resource strategy analysis as described at a high-level in Table L - 2.

Table L - 2: Simulation Descriptions

Simulation	Scenario/Sensitivity Supported	Description
Constrained Resources and Transmission	Resource and Transmission Risk: Constrained Resources and Transmission	Constrains supply-side resources in the near-term (first 6 years), limits transmission to the existing system, and delays emerging technologies by 10 years.
Existing Transmission	Resource and Transmission Risk: Changing Transmission Availability	Existing transmission and projects that have already started construction
Transmission Plus	Resource and Transmission Risk: Changing Transmission Availability, Slower Demand-Side Availability	Transmission including what was included in the WestTEC 10-year study
Transmission Max	Resource and Transmission Risk: Changing Transmission Availability	Transmission including and additional to the WestTEC 10-year study
Emerging Technology Costs 25% Lower	Resource and Transmission Risk: Changing Emerging Technology Costs	Cost assumptions for emerging technologies are 25 percent lower. Transmission including what was included in the WestTEC 10-year study
Emerging Technology Costs 50% Higher	Resource and Transmission Risk: Changing Emerging Technology Costs	Cost assumptions for emerging technologies are 50 percent higher. Transmission including what was included in the WestTEC 10-year study.
Limited Short-Duration Storage Availability	Resource and Transmission Risk: Limited Short-Duration Storage Availability	Constrains the availability of short-duration (lithium ion) battery storage in the near-term (first 6 years). Transmission including what was included in the WestTEC 10-year study.
Evolving Federal Policy Landscape	Resource and Transmission Risk: Evolving Federal Policy Landscape	Assumes a change in Federal policy 2030, shifting to policies similar to Biden-era policies. Transmission including what was included in the WestTEC 10-year study.

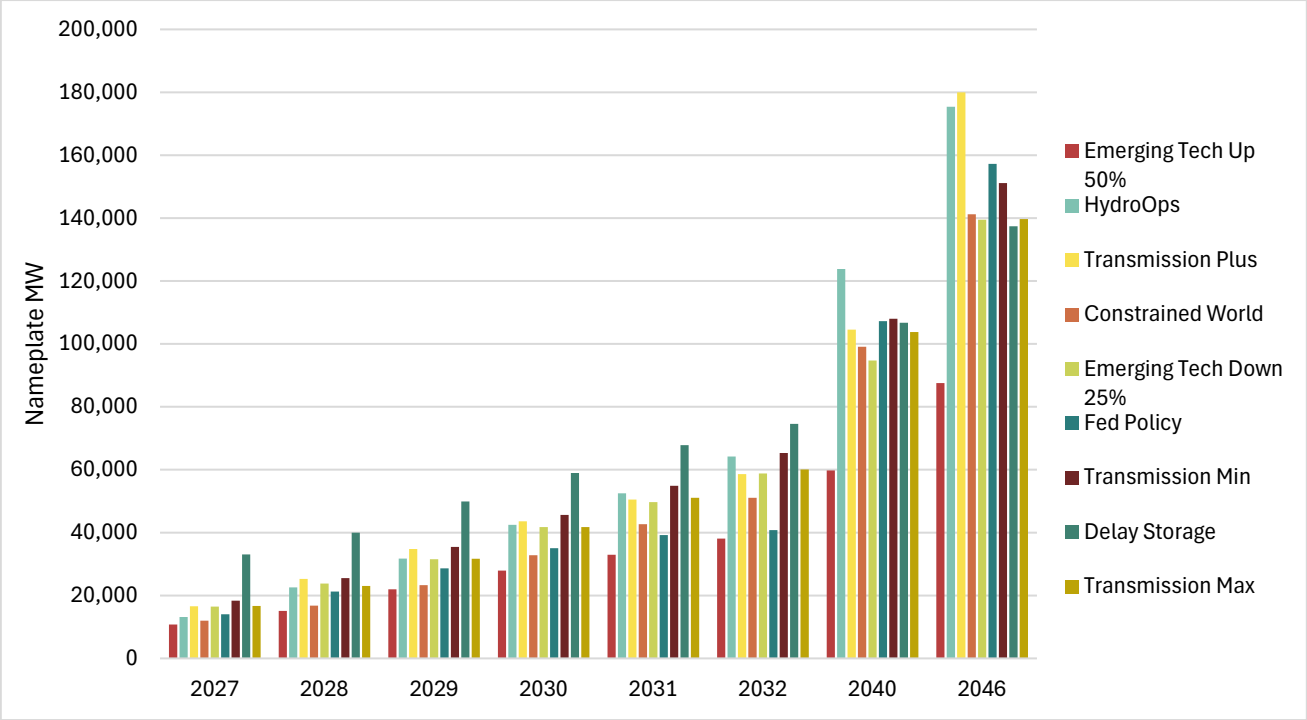
Simulation	Scenario/Sensitivity Supported	Description
Hydro Operations	Changing Hydro Operations: 2020 BiOp Flex Spill Operation, 2023 RCBA Operations, Recommended Spill and MOP Targets, Limited Flex Operations	Assumes Federal policies similar to Biden-era policies. Transmission including what was included in the WestTEC 10-year study.

Buildout Summary by Fuel Type

A portfolio of resource types, including emerging tech resources, were added in all cases for economics and to meet both policies and reserve margins. For policies associated with meeting zero emissions and renewable energy targets, there is a global modeling assumption that resources do not require specific siting to comply, thus the model often selects resources that are the most efficient at meeting these policies agnostic of location other than the convenience of higher resource availability, connectivity, or lower price. However, certain sensitivities incentivized location specific builds, by definition, due to emissions pricing policies and diversity of availability. Below the buildouts are broken apart by different new resource types: variable energy resources (uncertain fuel availability), natural gas resources (on-call fuel), short duration storage and mid/long duration storage (can shift capability but require more energy input than output).

Variable energy resources (VER) builds are driven primarily by the confluence of economics and policy. Emissions pricing in Canada, California, and Washington, which combined account for around 60% of the WECC demand, drives most early VER build. Existing state and local clean energy policies drive VER builds in the mid 2040's. Additionally, existing renewable portfolio standards policies drive some VER builds starting in 2030.

Figure L - 2: Variable Energy Resources Build Outside the Region



As can be seen in Figure L - 2, many of the sensitivities have similar VER builds. However, delays in short duration storage seem to cause more VER builds earlier in the study. Higher priced emerging technology resources drive down the overall VER build due to worse economics for longer duration storage assets which are more useful in a portfolio with wind generation which tends to be the majority of VER build in the early and middle years of the study due to the current saturation of solar generation in the existing system. This effect can be seen in Figure L - 3 and Figure L - 4.

Figure L - 3: Onshore Wind Build Outside the Region

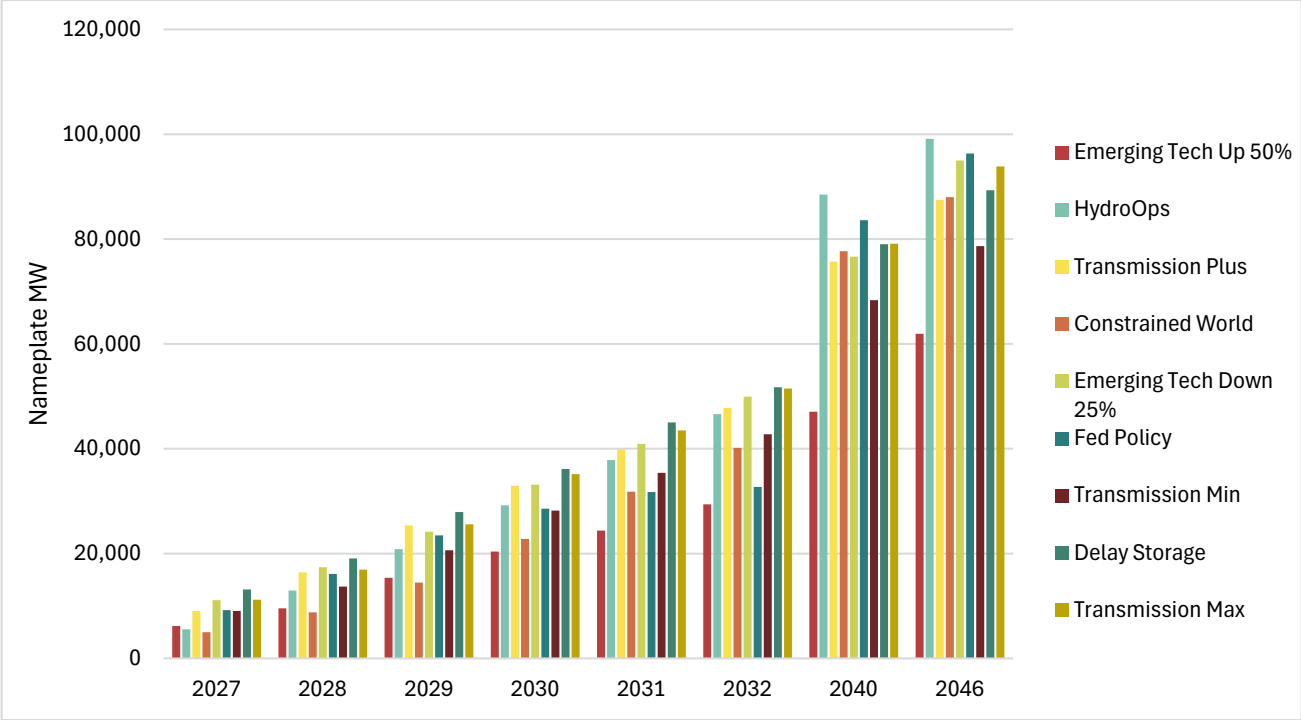
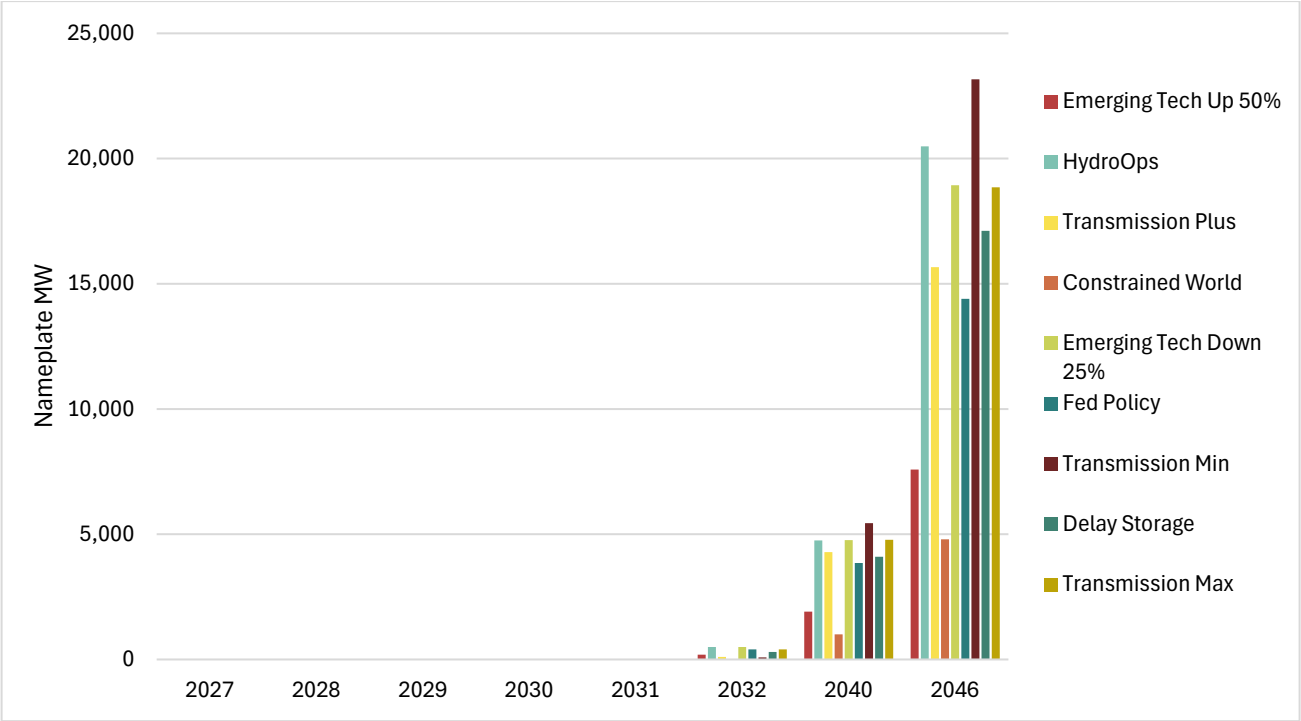


Figure L - 4: Longer Duration Storage Resources Build Outside the Region



Other than pumped storage, most longer duration storage resources are considered emerging technology in the Ninth Power Plan. Due to delay in availability of long and mid-duration storage in the Constrained Resource and Transmission sensitivity and the higher cost in the Emerging Tech

Uncertainty sensitivity with 50 percent higher investment costs, those sensitivities had considerably less longer duration storage. However, depending on its availability it was acquired in significant amounts in all sensitivities, many times up to the available purchase limit. Additionally, longer duration storage had a higher peak capacity contribution towards meeting reserve margins than shorter duration storage and seemed to be key in the portfolio approach of meeting those criteria.

Shorter duration storage resources are broadly available and new stand-alone storage was built in all the sensitivities but was specifically higher where longer duration storage was less available or more expensive as seen in Figure L - 5 and Figure L - 6.

Figure L - 5: Stand Alone 4 Hour Battery Build Outside the Region

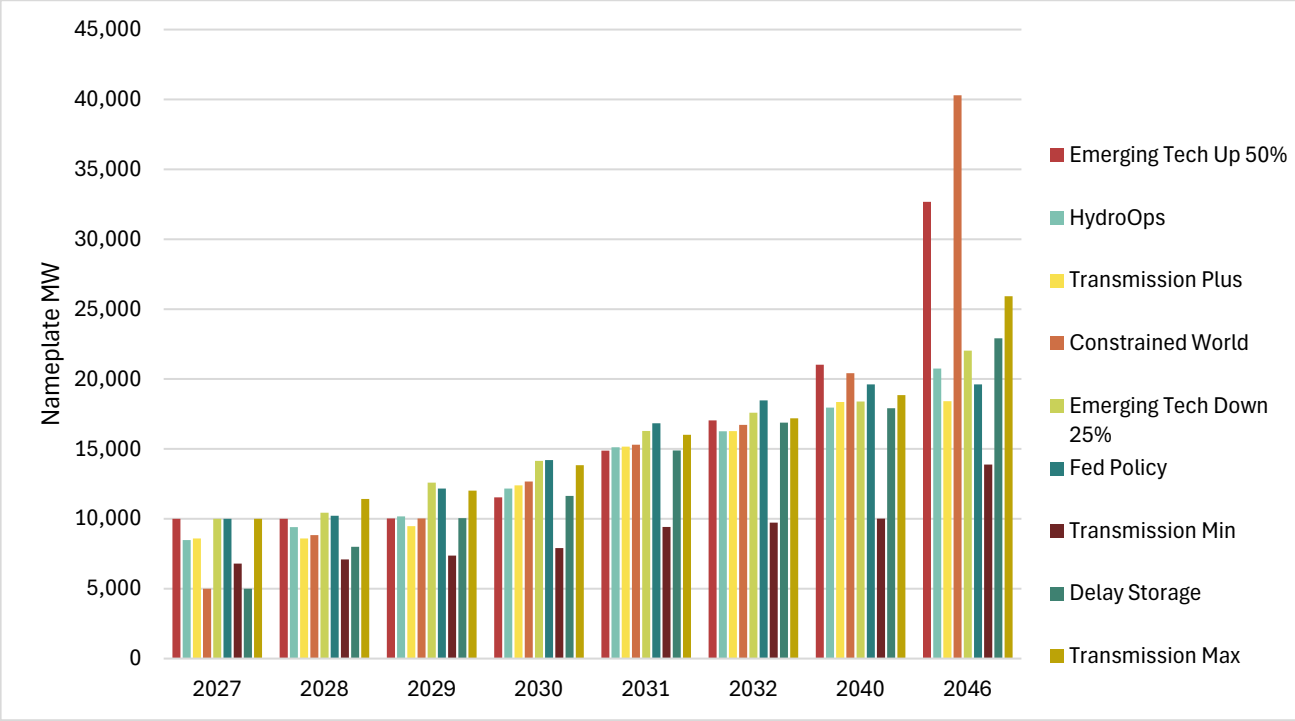
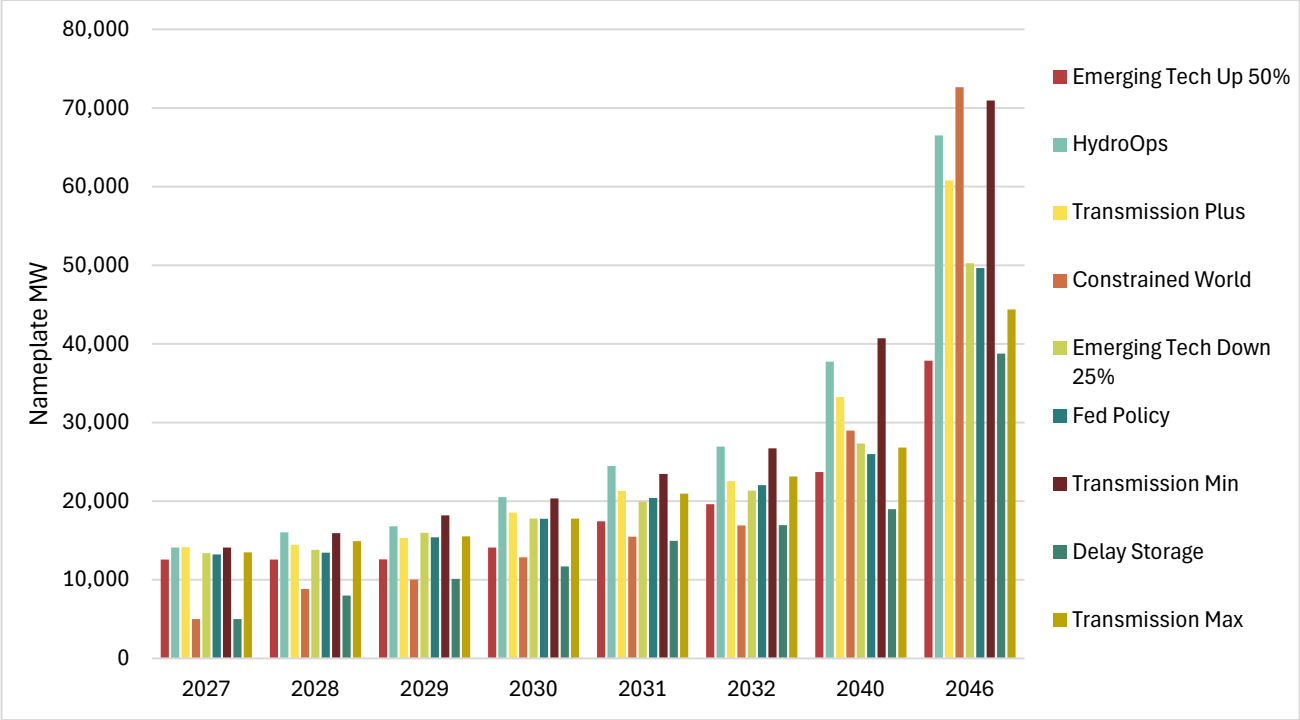


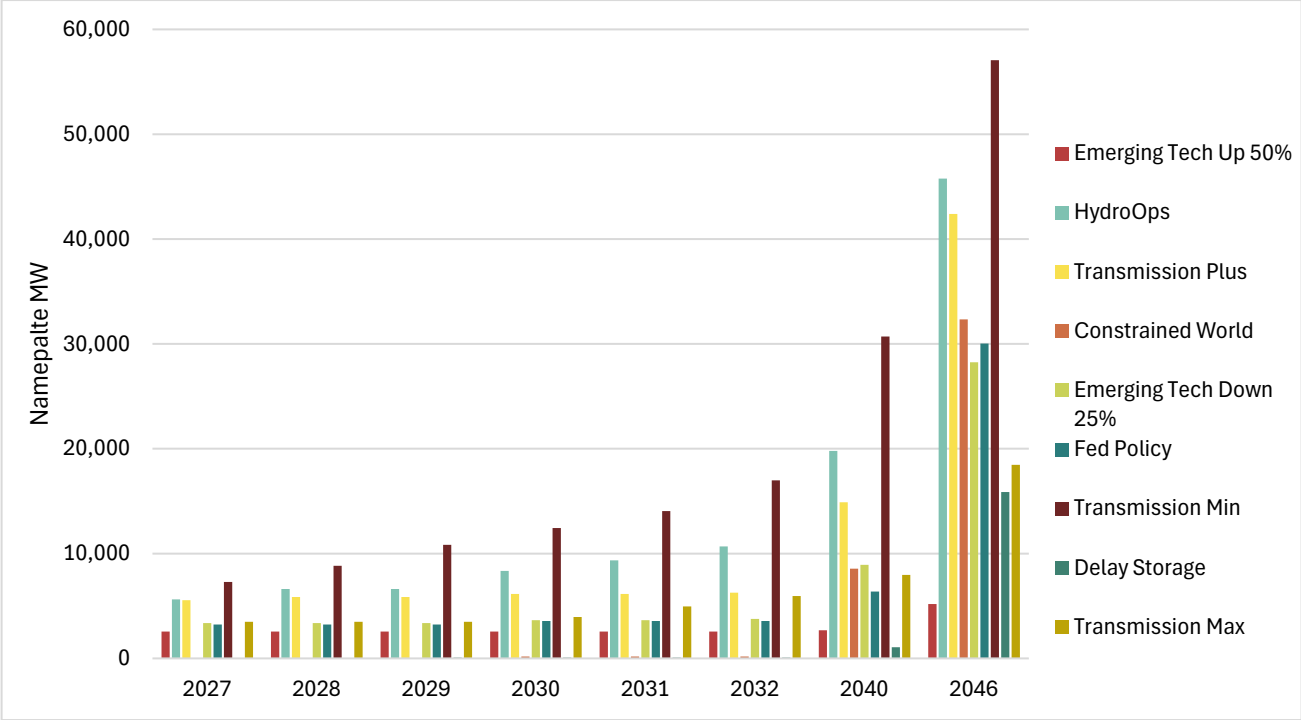
Figure L - 6: Short Duration Storage Build Outside the Region



Interestingly, while the total amount of stand-alone short duration storage is lower when there is less transmission, the model chooses to build a significant amount of short duration storage with solar via a solar hybrid resource in that sensitivity as can be seen in Figure L - 7.[5]

[5] Note that Figure L - 7 shows solar hybrid build by the nameplate megawatts of the inverter. In other words, since the hybrids are treated as a one-by-one hybrid, if the nameplate is listed as 100 megawatts, that indicates there is a hybrid with 100 megawatts of 4-hour battery and 100 megawatts of solar.

Figure L - 7: Solar Hybrid Build Outside the Region



Natural gas plants were acquired in most jurisdictions where they were allowed and/or did not have zero emissions policy targets. In the sensitivities, where emerging tech resources were higher cost or delayed and the sensitivity when less transmission was available, natural gas resources were acquired in larger quantities per Figure L - 8. New natural gas plants support reserve margins and displace less efficient thermal plants on the margin. No assumptions about conversion of newly acquired gas plants to another fuel in the future was explicitly made and in general the gas plants purchased outside the region were primarily new combined cycle units which tended to slightly lower Mid-Columbia[6] power prices on an annual basis as can be seen in Figure L - 9.

[6] Mid-Columbia (or Mid-C) is a standard, liquid trading hub for wholesale power in the Pacific Northwest region trading on the Intercontinental Exchange (ICE).

Figure L - 8: Natural Gas Build Outside the Region

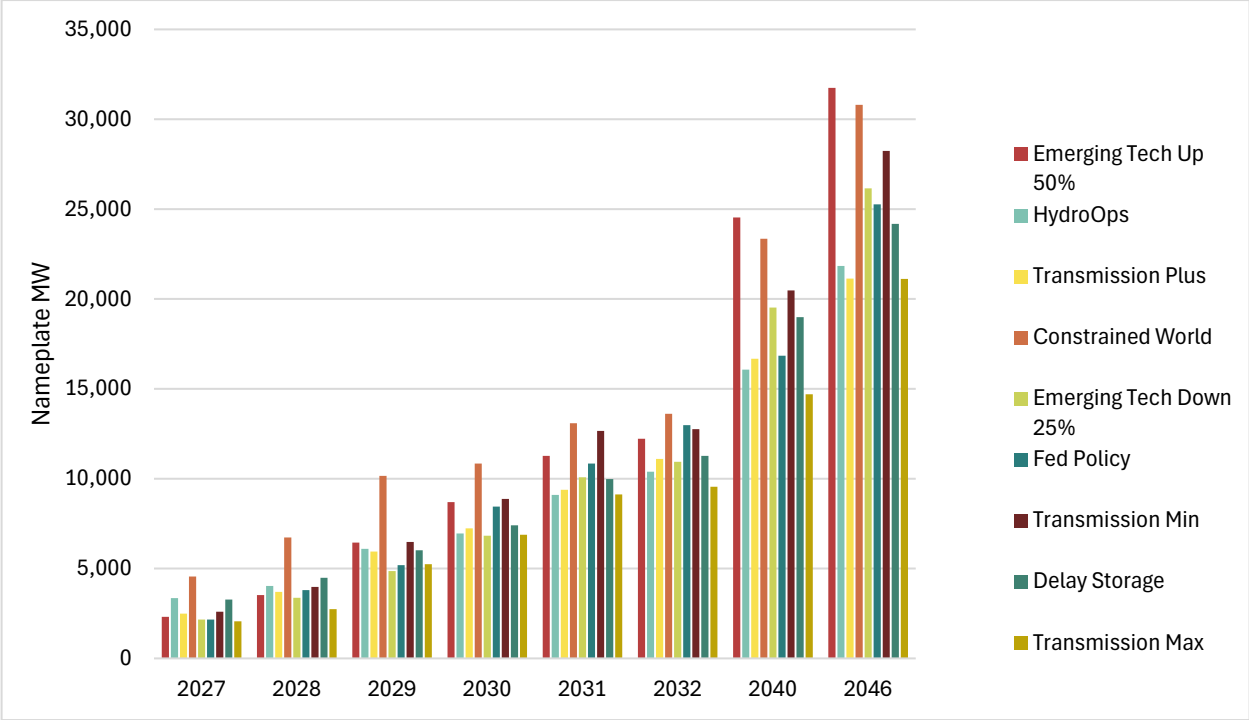
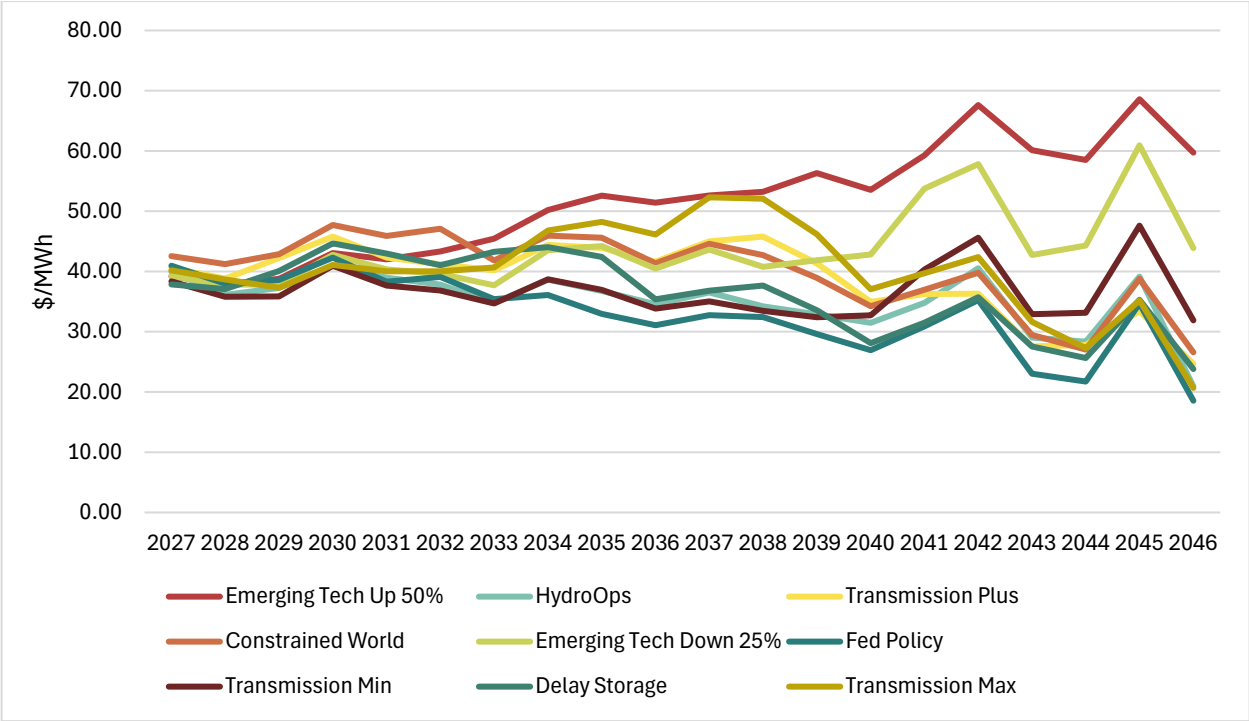


Figure L - 9: Mid-Columbia Annual Average Power Prices



In comparison, California prices go up over time as can be seen Figure L - 10. This price differential should incentivize regional exports to California in general and in particular on a seasonal basis in the summer where prices in California and throughout the west are higher than in the region as can be

seen in Figure L - 11 and Figure L - 12. This differential in seasonal pricing is similar to historical patterns as demand in the broader WECC (other than Canada) has traditionally peaked in the summer whereas the Northwest has peaked in the winter.

Figure L - 10: California Annual Average Power Prices

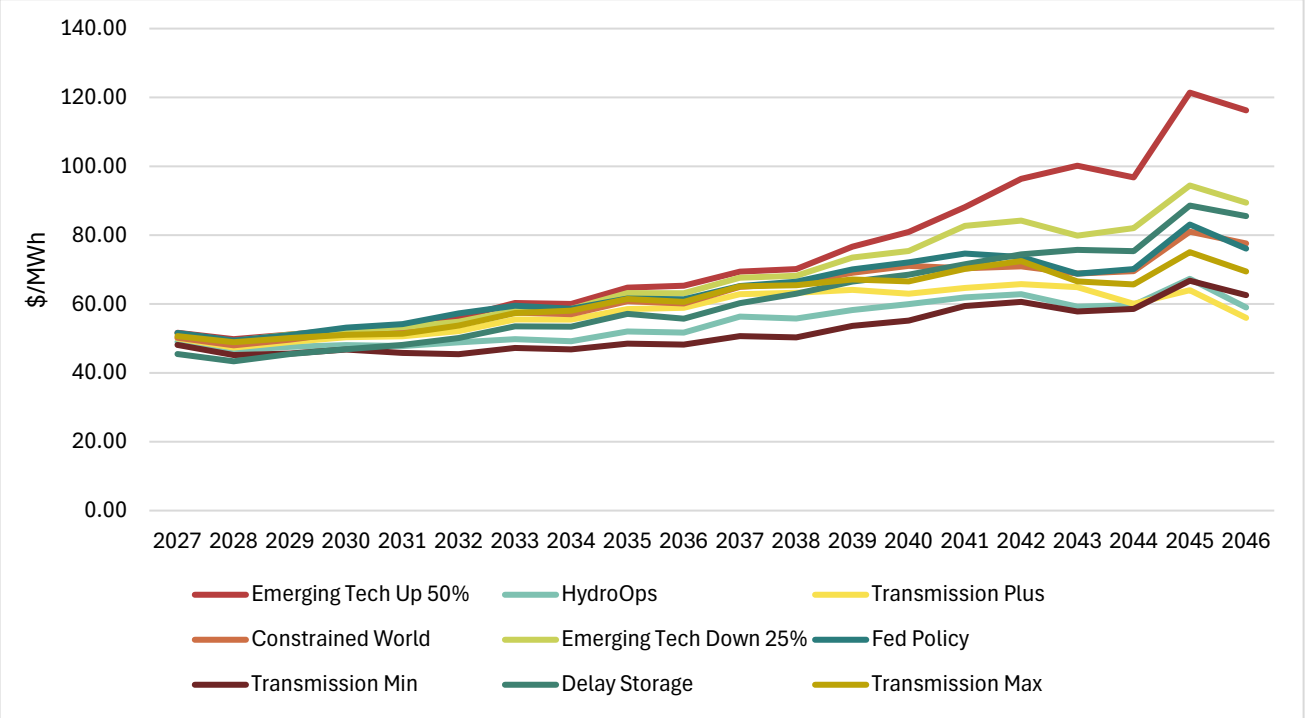


Figure L - 11: California Summer Average Power Prices

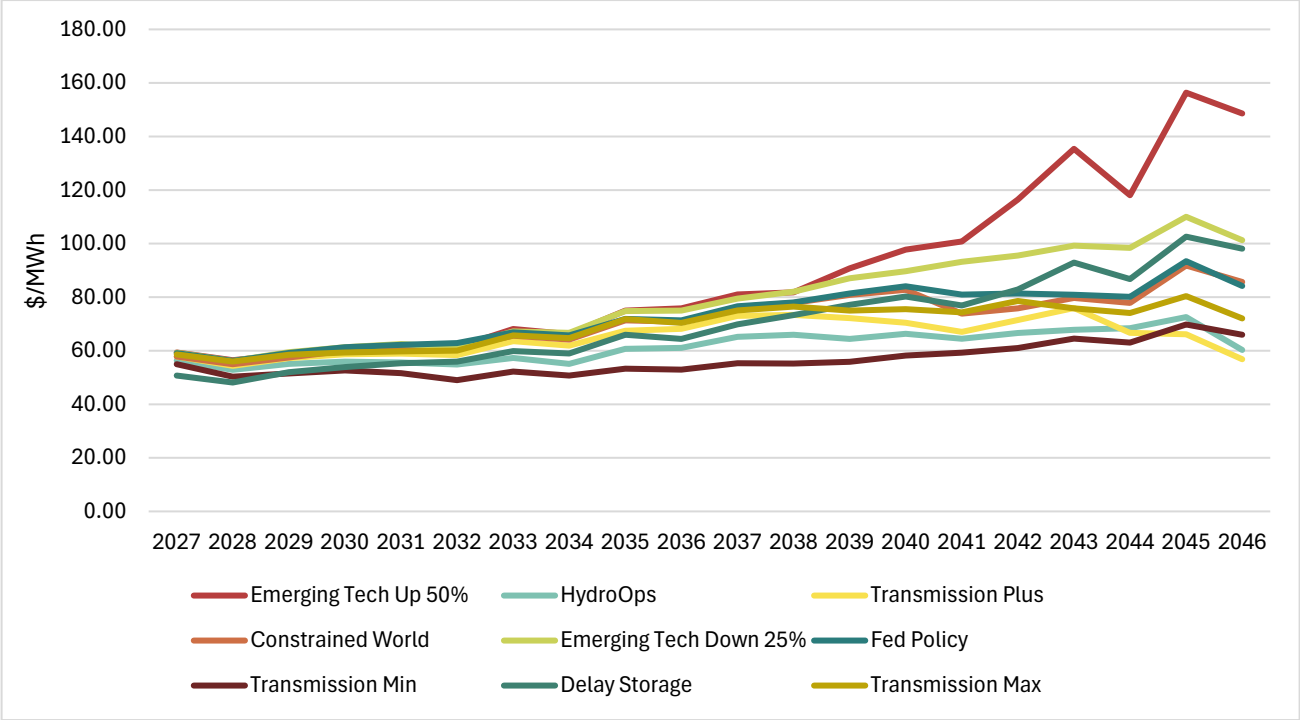
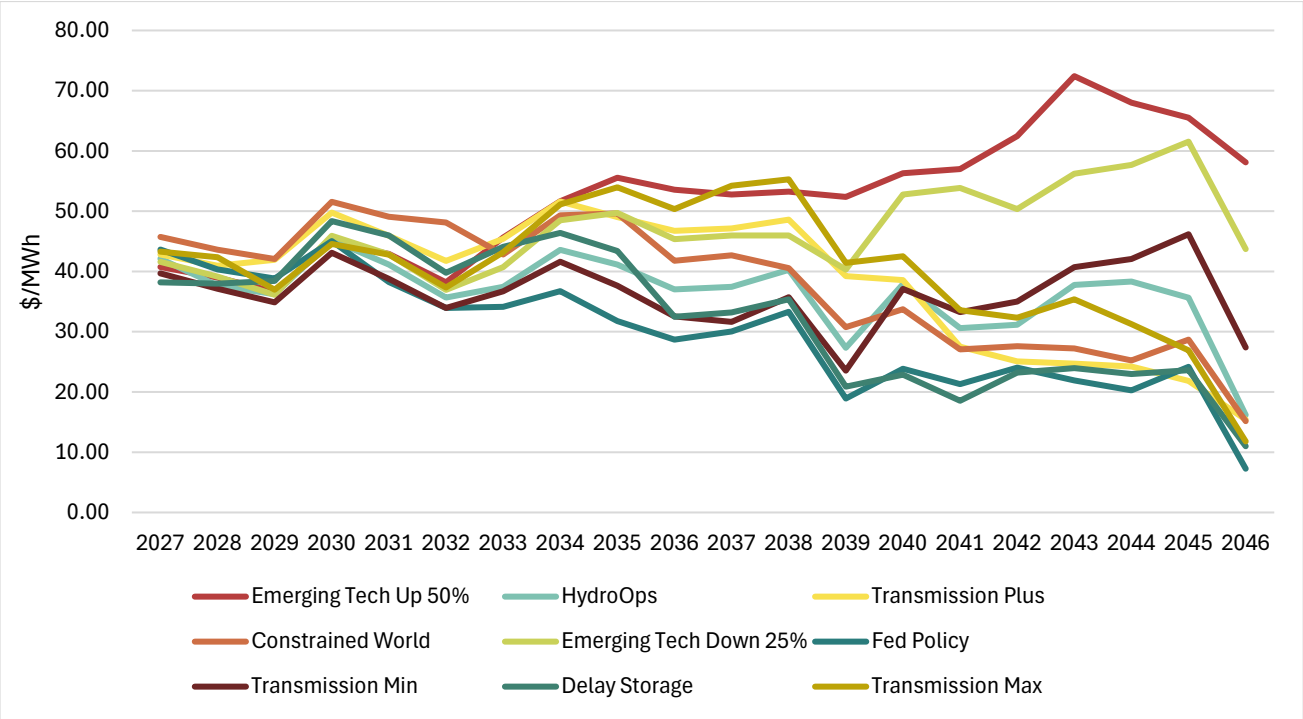


Figure L - 12: Mid-Columbia Summer Average Power Prices



However, note that both the region's and California's prices tend to increase a bit in the winter, as can be seen in Figure L - 13 and Figure L - 14, due to increased electrification in both load forecasts. This would indicate that perhaps the traditional seasonal hedge where the Northwest would count on

imports from California during poor hydro conditions may be less economic than in the past due to those increased California winter loads in the long term. However, it should be noted that, on average, the prices within the region stay flatter whereas California has lower prices midday and higher prices around the morning and evening ramp within the first five to ten years. Therefore, winter regional imports from California may continue to be economic in the middle of the day.

Figure L - 13: Mid-Columbia Winter Average Power Prices

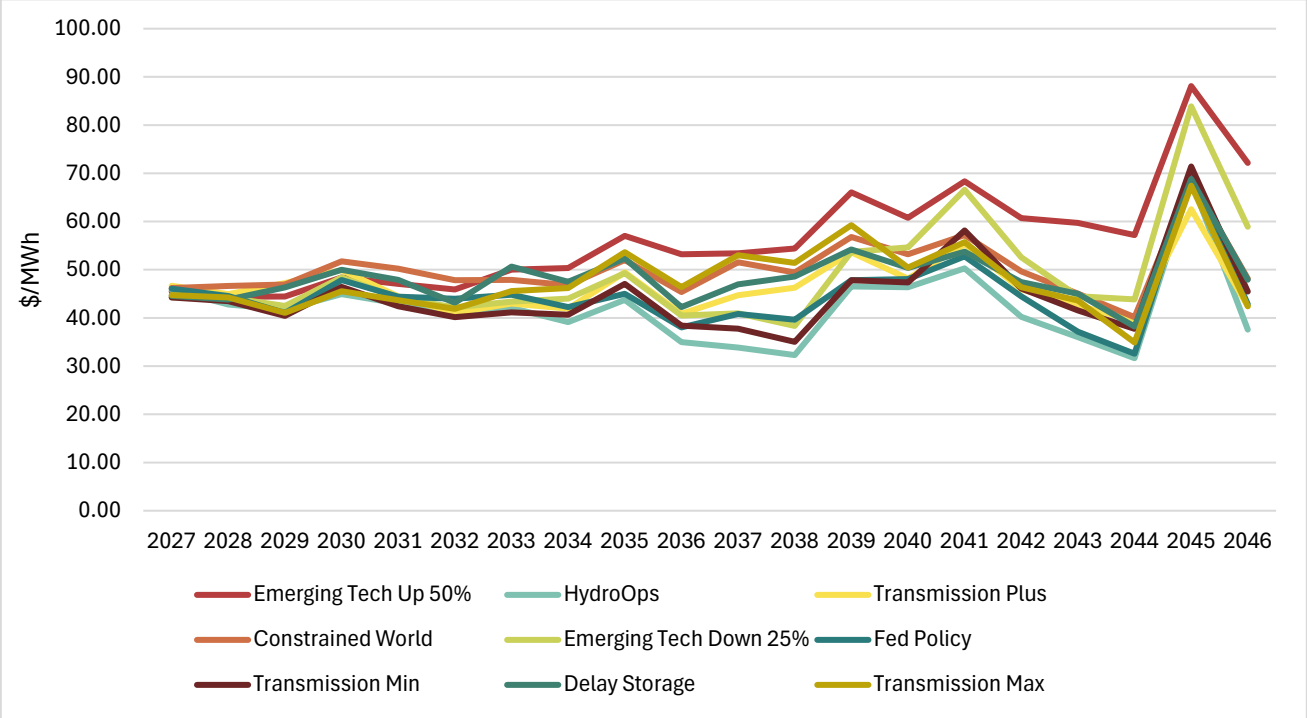
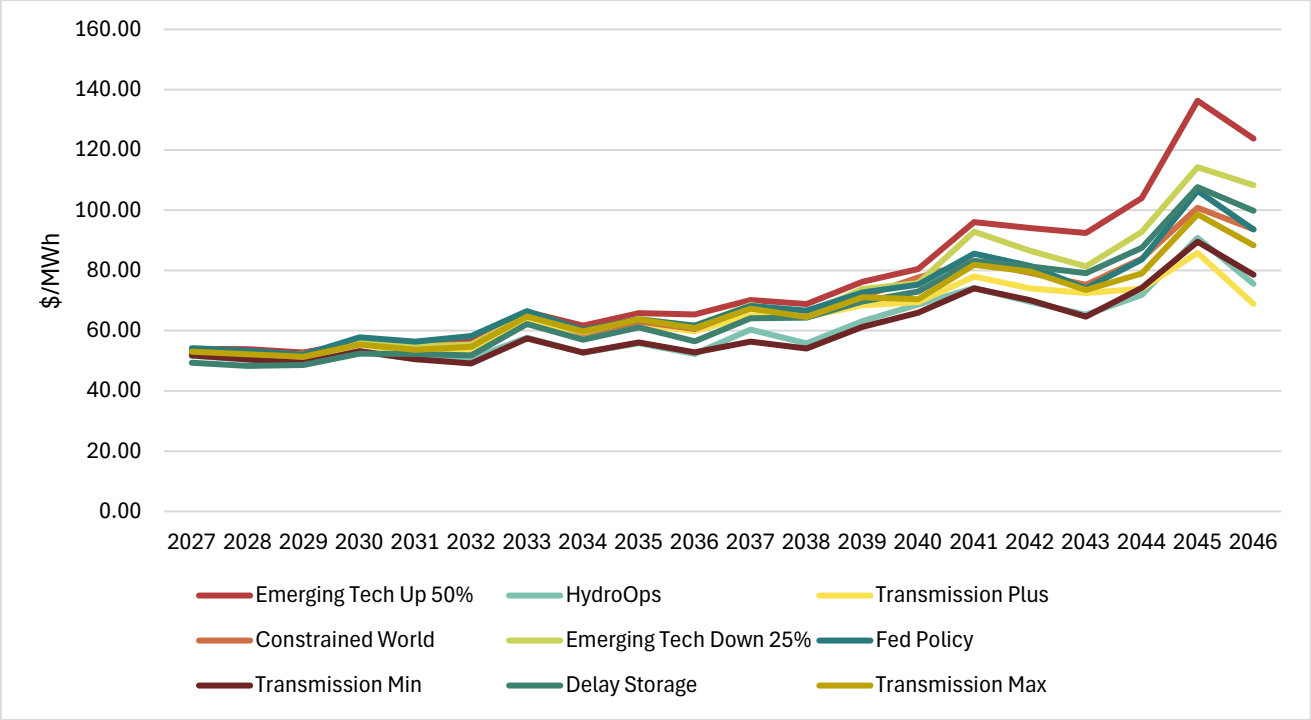


Figure L - 14: California Winter Average Power Prices



With an increase in transmission projects from the east side of the WECC to the west increasing connectivity per the transmission expansion described in Technical Appendices B and N, and the Mountain West sporting higher capacity factor wind resources that provide diversity to the existing solar buildout in the Southwest in conjunction with the increasing clean policy requirements over time, the Mountain West power prices are dropping over time as seen in Figure L - 15. Traditionally, due to limited connectivity with the Mountain West, less power was transmitted east to west, but that may change with the increased connectivity.

Figure L - 15: Mountain West Annual Average Power Prices

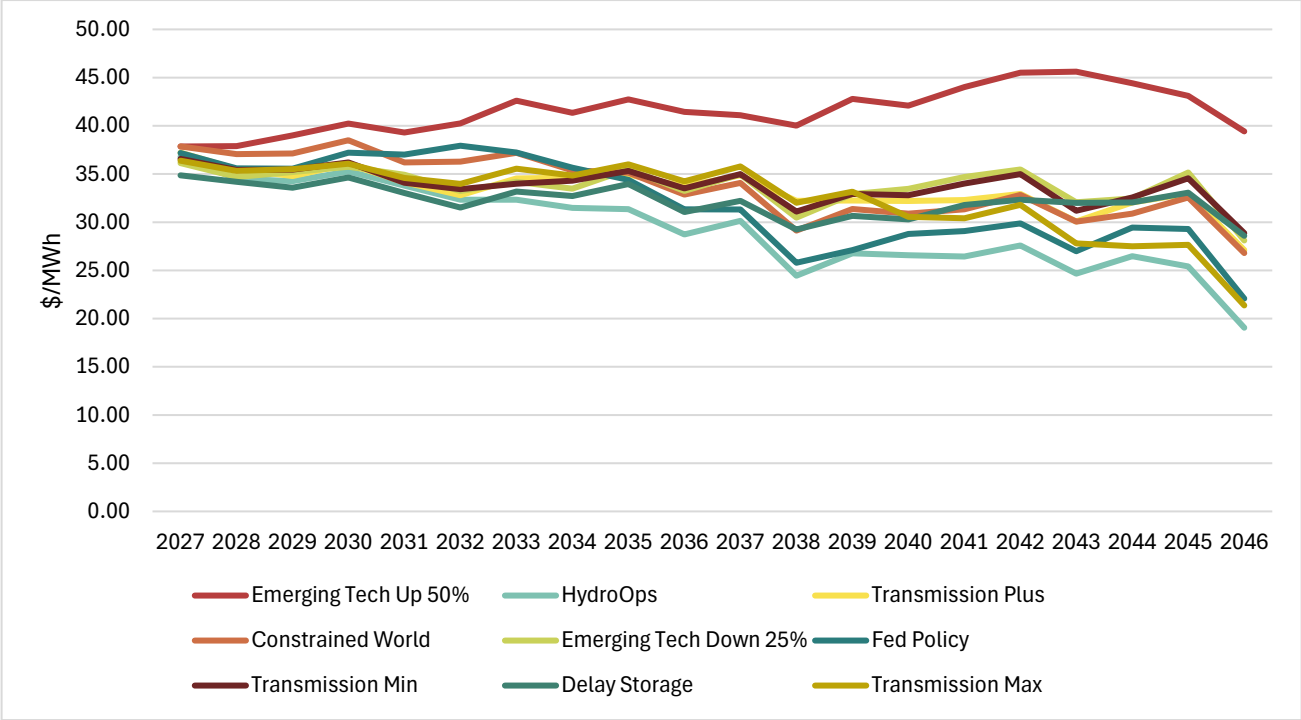
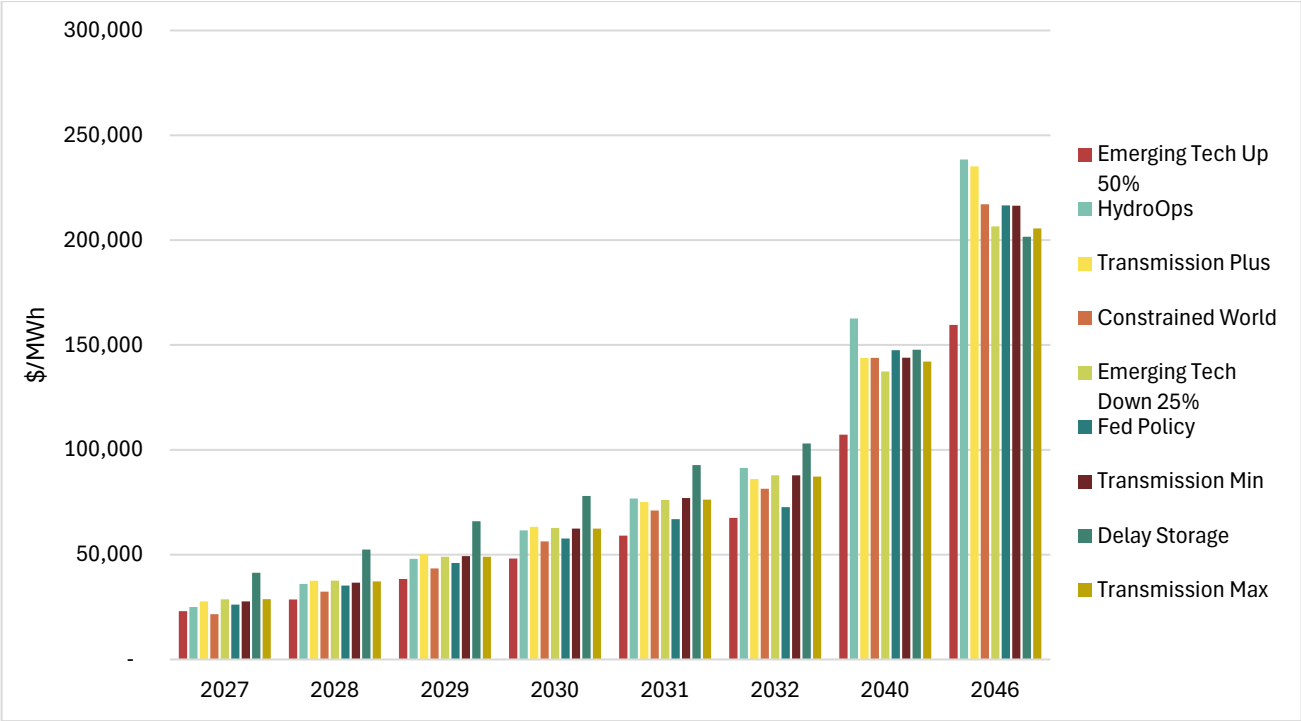


Figure L - 16: Total Out of Region Build in Nameplate Megawatts



In summary, the AURORA buildouts shown in Figure L - 16 seem to indicate that outside the Northwest resources will play a large role in WECC expansion, between 159 to 238 gigawatts by 2046. Most of the resources built are a balance of solar, wind, longer duration storage and gas. The

high prices in the winter morning and evening ramp periods and the lack of persistent negative pricing implies that the economics of the market long-term are likely to be quite different than previous recent studies. This is likely due to the effect of the increased load growth outpacing the policies. Additionally, traditional regional fundamentals around seasonal arbitrage are likely to shift due to policies, shifts in magnitude of seasonal demand, increased transmission connectivity and the resulting access to diverse power sources with lower variable costs.

Further Reference

For more information pertaining to the public process of vetting the assumptions and methodologies in this technical appendix please reference the following meetings:

- **July 17, 2025 SAAC meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-07-17
- **August 26, 2025 SAAC meeting:** https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-08-26
- **November 5, 2025 SAAC meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-11-05
- **January 6, 2026 Council meeting:** https://www.nwcouncil.org/fs/19713/2026_01_3.pdf#page=8

Technical Appendix M: Needs Assessment Results

Contents

Introduction 1
Council's Adequacy Criteria 2
Metrics and Thresholds 3
Needs Assessment Methodology for Ninth Plan 8
Role of Planning and Adequacy Reserve Margins 8
Reminder of the Existing System and Data Assumption 21
Tested Sensitivities 22
Needs Assessment Results 26
Peak Planning Reserve Margin 28
Energy Adequacy Reserve Margin 29

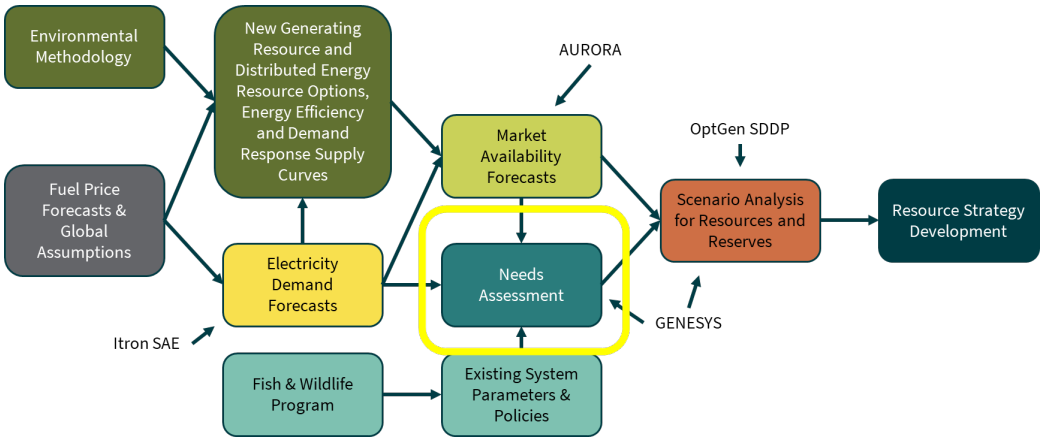
Introduction

The needs assessment is an important component of the Power Plan process to evaluate the need – also known as the resource gap – in a future year close to the end of the action period. Meeting this need is necessary for the region to be adequate. For the Ninth Plan, the needs assessment analyzed 2031. The need is evaluated with GENESYS, the Council's adequacy model, a multi-stage production cost model that co-optimizes energy and reserves while accounting for fuel use, forecast error and system constraints. Using the Council's multi-metric adequacy framework, the need is translated into capacity and energy signals for OptGen, the portfolio expansion model. These signals are called planning reserve margins (PRM) for capacity, and adequacy reserve margins (ARM) for energy. Both the PRM and ARM serve as a percentage above load that must be met to be considered adequate. OptGen then determines a resource strategy that meets the region's needs under different futures, ensuring OptGen's resource builds are resource adequate, which is then tested back in GENESYS to confirm adequacy

The needs assessment takes place at an important junction in the Power Plan process. It occurs before the portfolio model (OptGen) is run, and takes inputs from the market availability forecasts,

electricity demand forecasts, and existing system parameters and policies to simulate the Northwest power system in a future year as can be seen in Figure M - 1. [1]

Figure M - 1: Power Plan Process



The needs assessment is done for multiple sensitivities in 2031, which align with the scenarios and sensitivities in the Ninth Plan. Each needs assessment test creates a specific PRM and ARM to be used with the corresponding scenario in OptGen. [2] While the PRM and ARM inform OptGen, the resulting resource buildout still needs to be tested in GENESYS to ensure the adequacy criteria are satisfied. This step – known as the adequacy check – is not part of the needs assessment, but comes later in the resource strategy development.[3]

A distinction should be made between the Council's needs assessment and adequacy assessment. Needs assessments are conducted during a power plan to define the need that the region is facing in the future year. The needs assessment does not contain new resources and typically sees a resource deficit. An adequacy assessment looks at a future year with power plan recommended resources included, with the goal of ensuring that strategy provides for an adequate system.

Council's Adequacy Criteria

Though the need is defined in terms of the PRM and ARM, it is based on the Council's multi-metric adequacy criteria. While in the past adequacy was determined if a strategy resulted in a Loss of Load Probability (LOLP) of 5% (no more than one in 20 years with any shortfalls), the new multi-metric criteria ensures specific frequency, duration, and magnitude perspectives are met based on shortfall risks the region wants to protect against.

[1] See Technical Appendix K - Modeling Framework, Technical Appendix L – Wholesale Market Availability Results, Technical Appendix F – Electricity Demand Forecast, and Technical Appendix B – Existing System Parameters and Polices
[2] See Technical Appendix N – Scenario Modeling and Results.
[3] Ibid.

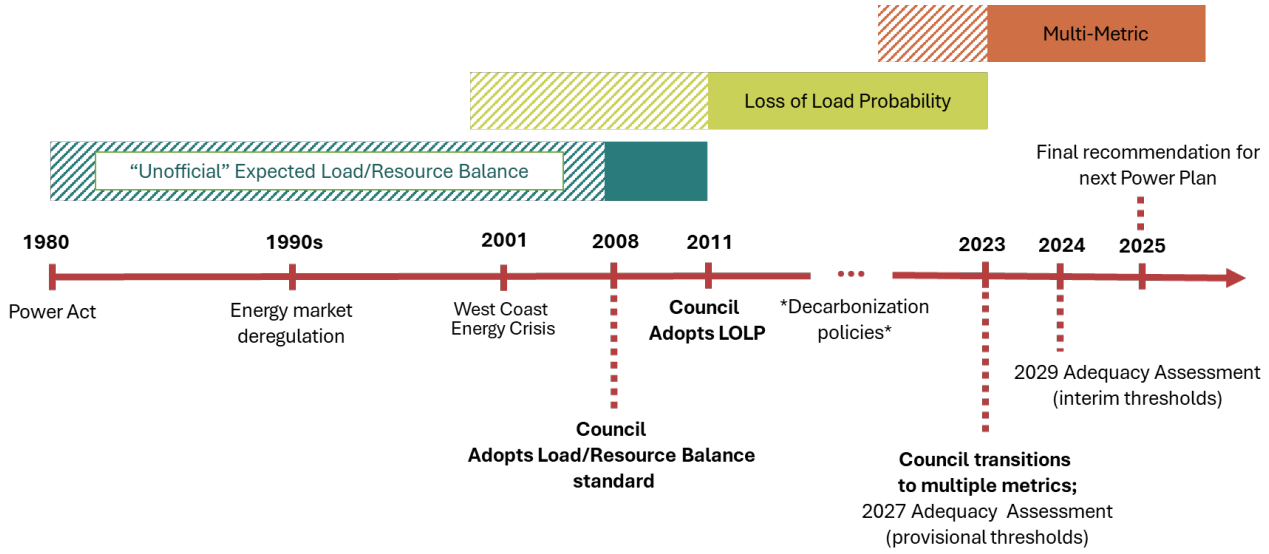
Council staff closely engaged with the Resource Adequacy Advisory Committee (RAAC) and regional partners to define and quantify the shortfall risks to avoid, and which specific metrics and thresholds are associated with them. [4] Overall, the region is considered adequate if the adequacy metrics indicate that the simulated shortfall record statistics are at or below the risk tolerance for the frequency, duration, and magnitude of events.

Part of this process was defining and quantifying risk of taking emergency measures into account (more extreme actions utilities and decision-makers can take to avoid a curtailment event). Though these emergency measures are not modeled in Council tools, understanding the characteristics of simulated shortfalls sheds light on frequency, duration, and magnitude of emergency measures that would be necessary to mitigate events. As such, staff collaborated with stakeholders on aggregating regional emergency capabilities and considering the risk tolerance for using (and not over relying on) these emergency capabilities.

Metrics and Thresholds

The Council's process to evaluate the metrics and threshold took several years, with 2022 dedicated to developing a provisional framework and culminated in official adoption of the proposed multi-metric criteria in April 2025,[5] seen in Figure M - 2.

Figure M - 2: Council's Evolving Approach to Adequacy



The first use of the provisional multi-metric framework was in the 2027 Adequacy Assessment, which included provisional threshold ranges for each metric to capture both lower and higher risk tolerances. In January of 2023, the Council decided to transition to the new multi-metric framework –

[4] See Resource Adequacy Advisory Committee resources.
[5] See Proposed Final Adequacy Criteria for Ninth Plan, https://www.nwcouncil.org/fs/19330/2025_04_06.pdf.

while recognizing it will be an ongoing, evolutionary process – and tasked staff to collaborate with the region on finetuning the thresholds. Over the course of 2023, staff engaged with utilities, regional organizations, and public utility commissions to solicit feedback on the multiple metrics, thresholds, and approximation of emergency measures. Interim findings of the stakeholder engagement process were presented at the May 2023 Council meeting and the findings in January 2024 with the RAAC Steering Committee and Technical Committee that have since been updated per April 2025.

The metrics are calculated from GENESYS, which simulates the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a period when load or required reserves cannot be served by resources in the model. However, a shortfall in the model does not mean an outage will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the outage. Emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above the import limit (such as those that occurred during January 2024's winter storm event), and calls for conservation by government officials (as in the September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (like during the 2001 Energy Crisis). Council staff distinguished the emergency measures available to the region in two groups:

- Within Utility Control ("low lift"): refers to measures that are typically within a utility's control, such as relying on costly resources outside of the active portfolio, industrial back-up generators, load buy-back provisions, and larger and costlier market purchases above normal market reliance limits.
- Outside Utility Control (less desirable, "heavy lift"): refers to extraordinary measures of extreme cases where customers may experience direct impacts, such as official's call to conservation, emergency load shedding protocols (rolling brownouts), or curtailing fish and wildlife operations.

Using multiple metrics – frequency, duration, and magnitude – gives decision makers the opportunity to understand the adequacy risk and how it relates to reliance on emergency measures. To be deemed adequate, all metrics must be satisfied (within their thresholds), and they include: [6]

- Annual Loss of Load Events (LOLEV) of 0.2:
  Sets a limit for the expected frequency of shortfall events to not exceed one in five years
- Winter and Summer Loss of Load Events (LOLEV) of 0.1:
  Sets a limit for the expected frequency of shortfalls in winter and summer (each) to not exceed one in ten years

[6] For an illustrative example of the calculation method, see May 2023 Council's presentation "Multi-Metric Approach to Adequacy: Progress Report" slide pages 5-12 (other sections have been updated since).

- Duration Value at Risk (VaR) 97.5th Percentile:
  Sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures, not to exceed 8 hours in more than 39-out-of-40 years
- Peak Value at Risk (VaR) 97.5th Percentile:
  Sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude use of emergency measures, not to exceed 1,200 MW in more than 39-out-of-40 years
- Energy Value at Risk (VaR) 97.5th Percentile:
  Sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate energy use of emergency measures, not to exceed 9,600 MW in more than 39-out-of-40 years

The calculation methodology differs for LOLEVs and VaRs. For LOLEVs, the number of events throughout the years and those only in winter and summer are divided by the total number of simulations (90 in the case of the Council representing the 90 climate years) seen in the equations below. The resulting value can be interpreted as the average number of events in each year/season.

$$Annual\ LOLEV = \frac{\sum Events_j}{N\ simulations}$$

$$Winter\ LOLEV = \frac{\sum Events_{winter}}{N\ simulations}$$

$$Summer\ LOLEV = \frac{\sum Events_{summer}}{N\ simulations}$$

The tail-end VaR metrics instead focus on first creating the distribution of shortfall quantities, including: the distribution of unserved energy for every simulation, the distribution of maximum single-hour shortfall magnitude for every simulation, and the distribution of maximum shortfall event-duration for every simulation. Then, the 97.5th percentile of each distribution is calculated and is the metric value.

By bridging modeled shortfalls to the need of emergency measures, the Council's multi-metric adequacy framework is aimed at protecting against the risk of Outside Utility Control emergency measures. As such, quantifying the region's aggregate Within Utility Control's emergency measures, and setting the metric thresholds to those capabilities, enables a probabilistic approach to how often extreme measures (Outside Utility Control) are expected (but not which measure would be used).

This approach can be summed up as "Let's make sure any emergency measures aren't used too often" (satisfying LOLEV), and "For the vast majority of the time let's make sure the emergency measures we rely on are not used too long or are too big" (satisfying duration, peak and energy VaR). The significance of the VaR metrics at the 97.5th percentile with a threshold associated with Within Utility Control emergency measures means we can expect to avoid the extreme, less desirable, emergency measures 39 out of 40 years.

However, because it is difficult to fully and accurately account for the magnitude and duration of all emergency measures, staff recognize that thresholds are approximations. Further, there is no clear

line in the sand between magnitude of Within Utility Control and Outside Utility Control measures as these may vary by utility and circumstance. As such, the framework should be understood as an evolutionary process towards redefining tail-end system risk, rather than a complete characterization of emergency measures.

Lastly, an important connection should be understood between the metrics, specifically the thresholds, and the Council's longstanding market reliance limit. This limit – 2,500 MW in winter and 1,250 MW in summer – was developed with the Resource Adequacy Advisory Committee and acts as a philosophical hedge against over relying on market imports at time of system stress. As the market is a dynamic resource in GENESYS, it means the shortfall record – the direct link to calculating adequacy metrics – is reflecting the shortfalls given the market limit. This means that the thresholds described above consider the market reliance limits and any future change to the market reliance limit would require an evaluation of how the thresholds (and emergency measures) would be influenced.

Loss of Load Events

As the frequency of shortfalls is equivalent to the frequency of using emergency measures, a limit can be set for the frequency of simulated shortfalls as it relates to preventing overly frequent use of emergency measures. The Council chose the Loss of Load Events (LOLEV) to meet this objective, which is the expected number of shortfall events per desired period. LOLEV is equal to the total number of shortfall events divided by the total number of simulation periods (for example, number of years or number of seasons). Because periods of most concern include summer and winter, staff heard feedback to align with the Western Resource Adequacy Program (WRAP) seasonal approach and decided to set a threshold value for both summer and winter at 0.1 (expected frequency of events to not exceed one in ten years in each season). However, risk may change over time, so considering shortfall risk throughout the year is important as well. Therefore, an annual LOLEV is also used to cover risk across a year set at 0.2(expected frequency of events to not exceed one in five years).

Duration Value-at-Risk 97.5th Percentile

Long shortfall events can indicate insufficient system energy (i.e. fuel). Long shortfall events can occur during periods of prolonged extreme weather (like during the January 2024 winter storm), due to fuel supply issues (for example a low water year), or other disruptions. The Council chose the Value at Risk (VaR) for shortfall event duration at the 97.5th percentile over all simulation years to capture this risk. To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (and noted as zero if there is no shortfall in a year). Then, the Duration VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years. The threshold for this metric is set to 8 hours, to reflect the minimum shortfall duration that could lead to severe customer risk.

Peak Value-at-Risk 97.5th Percentile

The Pacific Northwest's power supply has historically been capacity long, but energy short. The region has had an excess of peaking capacity but is limited by the water supply that powers the hydroelectric

system, which provides more than half of the grid's nameplate capacity. While the hydroelectric system's nameplate capacity is about 35,000 megawatts, it generates about 16,000 average megawatts per year, on average, and only around 12,000 average megawatts during a low water year. However, due to significant increases in loads, especially peaking loads of (heating and cooling and transportation electrification), alongside increases invariable energy resources, changes in hydroelectric operating constraints, and other added complexities, the region can no longer assume that it has sufficient capacity to meet all demand. Thus, it is important to include a metric to protect against excessively high-capacity shortfalls.

The Council chose the Value at Risk (VaR) for capacity shortfall at the 97.5th percentile over all simulation years to manage this risk. To calculate this metric, the highest single-hour shortfall for each simulation year is recorded. The Peak VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. While this frequency is smaller than that chosen for the LOLEV, it represents the risk of exceeding Within Utility Control emergency measure capability, whereas the LOLEV frequency represents the risk of using emergency measures too often.

The limit for this metric represents the amount of single hour demand the region is willing to risk. As such, the limit is set equal to the aggregate amount of emergency peaking capability. The risk of curtailment is high when the Peak VaR97.5 exceeds this limit because avoiding a loss of service depends on the availability of emergency measures not accounted for in the adequacy limit. The threshold for this metric is set at 1,200 megawatts (the amount of emergency resources estimated to be in the region). Note that using the full 1,200 megawatts of resource would require coordination across multiple utilities.

Energy Value-at-Risk 97.5th Percentile

The region's power supply is energy limited because hydroelectric resources make up the lion's share of the supply. It is important to include a metric to protect against annual energy shortfalls. Unlike the capacity metric, whose limit is tied to the highest single-hour shortfall, the energy metric is tied to the entire year's unserved energy. This is because energy shortfalls are often equated to a lack of fuel, whereas capacity shortfalls are often equated to a lack of steel-in-the-ground capability. Once the capability is sufficient to offset the highest capacity shortfall, all remaining shortfalls can also be offset. However, sufficient fuel to offset the highest energy shortfall does not guarantee that other energy shortfalls throughout the year can also be offset.

The metric chosen to achieve this objective is the VaR for energy shortfall at the 97.5th percentile over all simulation years. To calculate this metric, total annual unserved demand for each simulation year is recorded. The Energy VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Similar to Peak VaR, this frequency is smaller than that chosen for the LOLEV, representing the risk of exceeding Within Utility Control emergency measures.

The limit for this metric represents the amount of annual energy demand the region is willing to risk. As such, the limit is equal to the aggregate amount of emergency energy generating resources. But because it is difficult to accurately assess the amount of available emergency energy, the limits assumes the "worst acceptable" annual unserved energy as the longest allowed 97.5th duration of 8

hours, where each hour has the largest allowed 97.5th hourly peak magnitude of 1,200 MW, the limit can be set at 9,600 MWh for the year.

Needs Assessment Methodology for Ninth Plan

As discussed in the introduction, the outcome of the needs assessment is the signal to OptGen, the capital expansion model, to develop a resource strategy for the region to be adequate in a future year. The need is calculated in GENESYS, and it can be defined in terms of energy and capacity needed for adequacy. These values are then translated into a percentage-based planning reserve margins (PRM) for peak, and an annual energy target for the adequacy reserve margin (ARM).

Role of Planning and Adequacy Reserve Margins

The PRM tells the model the level of resources required to stay adequate for a specific period. For example, a 20% PRM in January tells OptGen that the resource strategy should ensure resource (including generation and demand side management) have a capability at least 20% above load for the month of January. For example, if the January load is 34,000 MW, then the resource capability should be 34,000 MW+ 6,800 MW (20% of load) for a total of 40,800 MW.

For the ARM, the model is given an annual energy target for new resources only, effectively telling the model how many new resources in addition to the existing system are needed for adequacy. For example, an ARM of 5,000 aMW tells the model to acquire new supply side and demand side resources that provide that level of annual energy.

To help guide the description, keep in mind that LOLEV and Peak VaR 97.5th percentile influence the PRM for peak capacity, and Duration and Energy VaR 97.5th percentile influence the ARM for energy.

Peak – Planning Reserve Margin

The PRM is derived from three important components, including the implied need to satisfy the adequacy criteria, the load resource balance (LRB) in regards to the capability of the existing system and load growth, and temperature-sensitive extreme conditions. The implied need to satisfy adequacy is derived from GENESYS's shortfall record, the LRB is derived from OptGen, and temperature-sensitive extreme conditions are derived from GENESYS-OptGen dynamics.

Defining Need from GENESYS

While GENESYS simulates the region's power supply, the determination whether the region is adequate is calculated in post-processing from analyzing the shortfall record. The shortfall record includes all hours in a year from all years in the simulation, and records 0 for no shortfalls or a positive value if there was a shortfall. In total, each study has 786,240 hours of observations (90 unique

climate years * 8,736 hours).[7] Part of the shortfall record development includes post-processing assumptions about whether the load forecast includes elastic loads. These loads, like hydrogen production, are assumed to be curtailed (i.e. not met) during stressful system conditions. However, as GENESYS does not differentiate elastic from inelastic loads, the magnitude of the elastic load needs to be netted out of the shortfall as it theoretically would have been curtailed. In the High Growth pathway, there is 461 aMW of hydrogen, and therefore 461 MW are netted out of each shortfall in the High Growth trajectory. In other trajectories, shortfalls below 25 MW are assumed to be market noise and therefore removed from the record as well.

From this record, the annual and seasonal LOLEVs are calculated, as are the 97.5th percentiles of longest durations, peak magnitude, and annual unserved energy. The post-processing analysis also includes a dataset of all shortfall events identified by scenario, month they occurred, day in the month, event duration, peak hour (MW) in the event, total event unserved energy (MWh), an hourly dataset of all shortfall hours, and monthly statistics for each of the duration, peak, and energy Value-at-Risk 97.5th percentiles. If any metric is violated, there is an implied capacity or energy need that, theoretically, if it were to be added to the system, would make the system adequate. The detailed shortfall dataset then helps identify the temporal and magnitude dimensions of the need.

An important note – there may be hours where GENESYS computation reaches an infeasibility, and no value is recorded until the computation reaches another stage or seam where it can reach a solution. Though infrequent, it tends to happen when the model is experiencing a simultaneous convergence of challenging water conditions and system constraints that make finding a solution infeasible within the time allowed. As it is theoretically possible to "miss" shortfalls if they could have occurred in these missing hours, staff proposed a conservative approach of replicating the applicable data of the closest available previous day or days. For example, if a shortfall happened on Feb 10th from 10-12pm, but then Feb 11 experienced an infeasibility, the shortfall record will also include the same Feb 10th shortfall from 10-12pm on Feb 11. This is a post-processing modification, and why it is possible to see "duplicated" events in the shortfall record.

Satisfying LOLEV

With most adequacy metrics the system is not designed to be 100% adequate under all conditions. An adequate system will still, in modeling, have outages. In the adequacy assessment, we define these outages as “keep.” For example, a winter LOLEV of 0.1, calculated from 90 simulations, means no more than 9 (0.1 * 90 = 9) events may occur in the winter. However, if the simulated shortfall record had 20 events in winter (LOLEV of 0.22), then 11 of them would have to be mitigated to reduce the number of events to 9, the allowed limit. In other words, any event past the allowed simulated threshold must be mitigated – and the MW capacity to do so is the implied need to satisfy LOLEV.

This means that the first step in identifying the need requires categorizing each event as either “keep” (allowed to occur under the adequacy thresholds) or “mitigate.” Theoretically, if the largest peak

[7] For multi-stage modeling purposes that require dividing the year to 52 stages (weeks), December 31st is ignored.

hourly shortfall is mitigated by adding the capacity to satisfy it, then all remaining shortfalls would also be mitigated, resulting in an LOLEV of 0. This would result in an overly adequate, and expensive, system. On the opposite side, adding capacity to satisfy only the smallest peak shortfall would only mitigate 1 shortfall, resulting in an LOLEV of 0.21, still not adequate. The solution is in identifying the largest events that can be "kept" from the shortfall record, in this case the top 9 events, and then require the mitigation from the 10th event until the last one. The peak capacity to mitigate the 10th event is the implied need to satisfy LOLEV. This is the case whether there are 20 events, 100 events, or 2,000 events across the 90 simulations.

The Council's frequency criteria includes both an annual LOLEV of 0.2, and winter and summer LOLEVs of 0.1. This means that annually 18 events are allowed to be "kept" (0.2 * 90 simulations), but only 9 events are allowed each in winter and summer. This also means that a shortfall record with exactly 9 winter events and 9 summer events would be adequate, as annually there are no more than 18 (LOLEV 0.2) and both winter and summer have no more than the allowed 9 (LOLEV 0.1).

However, consider the case when the top 18 annual events have 11 winter events, 6 summer events, and one fall event. Annually speaking, all events would be categorized as "keep" and the system would be adequate from an annual perspective. However, the 11 winter events are above the 9 allowed to meet the winter LOLEV criteria. In this situation, the shortfall record needs to account for a seasonal category of "keep" and "mitigate" as well.

To reconcile the annual and seasonal differences, the analysis requires mitigation of annual, winter, and summer events to meet both thresholds (annual and seasonal). The question becomes which need, annual or seasonal, is the resulting signal. Here, the analysis requires breaking down the shortfall record by month, and then looking at the peak shortfall in each period that must be mitigated. If the winter and summer implied need is larger than the annual implied need for that month, then the seasonal need is the signal. If the implied annual need is larger than the implied winter and summer need, then the annual need is the signal.

Satisfying Peak VaR 97.5th Percentile

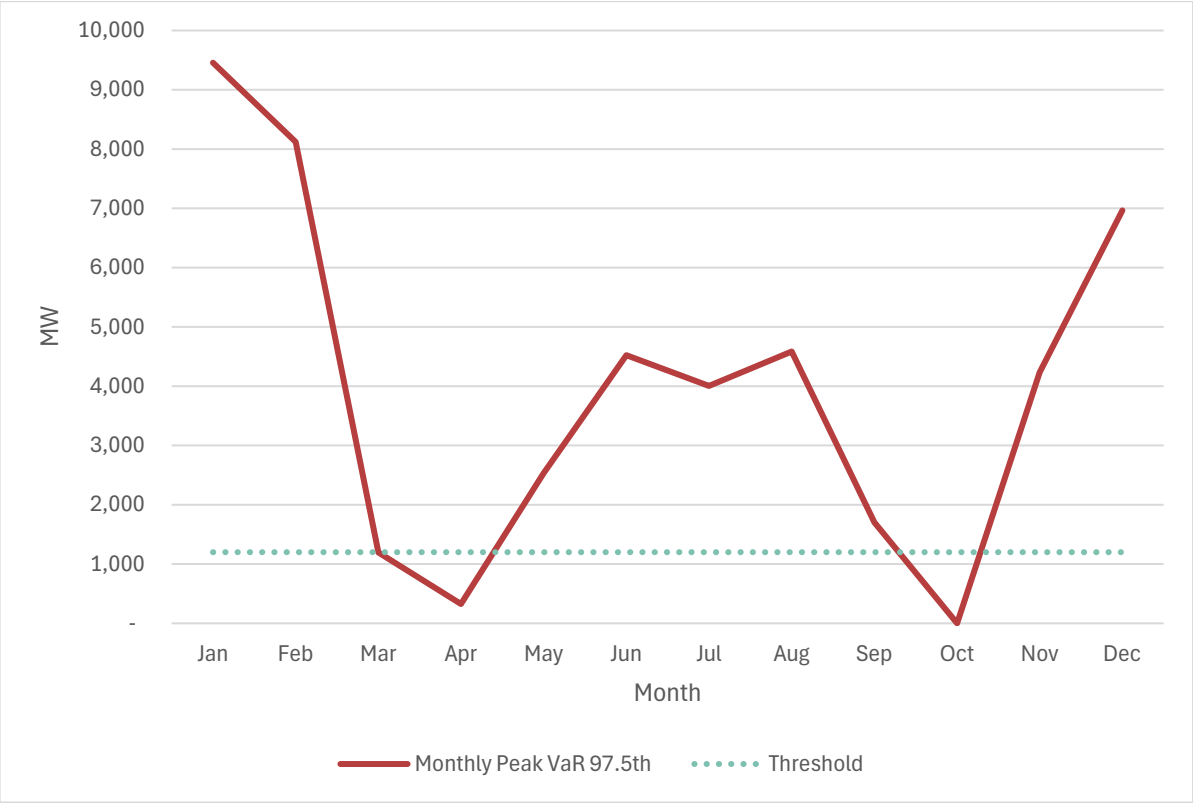
After calculating the implied monthly need to satisfy both annual and seasonal LOLEVs, the analysis turns to the implied need to satisfy the Peak VaR 97.5th percentile. While LOLEVs have a monthly component to the annual and seasonal LOLEVs, the Peak VaR is different.

As a tail-end metric from a distribution of maximum shortfalls, the implied annual need to satisfy the Peak VaR metric is the difference between the metric value and the threshold. If the metric result is, for example, 11,000 MW, then the implied need is 9,800 MW (11,000 – 1,200). Again, the 1,200 MW threshold is based on estimated emergency resource capabilities. Theoretically, if the system had an additional 9,800 MW of peaking capability, the shortfall record would reflect that all peaks would be 9,800 MW lower (or zero), and the system would be adequate.

Similar to LOLEV, a temporal nuance is needed to finetune the Peak VaR signal in OptGen. Building to the annual Peak VaR value every month would likely result in a resource overbuild, so the Peak VaR analysis requires understanding the monthly Peak VaR values. These are calculated by taking the

97.5th percentile of peak events within each month, seen in Figure M - 3, alongside the 1,200 MW threshold.

Figure M - 3: Example of Monthly Peak VaR 97.5th Percentile



Notice that the shortfalls are not equal throughout the year, with winter and summer months experiencing the largest shortfall risks, with other months are below the threshold. While the monthly VaR is not an adopted adequacy metric, it can be used to guide the decision on which month has the risk for highest shortfalls – in this example January. For the Ninth Plan the month with the highest risk is given the annual signal to protect against the annual peak.

Reconciling the Need Signal Between LOLEVs and Peak VaR 97.5th Percentile

Once the monthly need from both LOLEVs (annual and seasonal) and Peak VaR (guided by monthly Peak VaR) are calculated, the next step is determining if the month receives the annual Peak VaR or the LOLEV value. An example of this is seen in Table M - 1.

Table M - 1: Example Selection of Monthly Need Signal

	Annual Frequency (MW)	Seasonal Frequency (MW)	Monthly Peak VaR (MW)	Annual Peak VaR (MW)	Season	Is Seasonal_F > Annual_F?	Is Highest Monthly Peak VAR?	Is Annual VaR largest?	Monthly Need (MW)
Jan	7,743	9,245	9,457	9,845	winter	TRUE	TRUE	TRUE	9,845
Feb	8,270	8,270	8,121	9,845	winter	FALSE	FALSE	FALSE	8,270
Mar	1,482	-	1,195	9,845	shoulder	FALSE	FALSE	FALSE	1,482
Apr	3,305	-	326	9,845	shoulder	FALSE	FALSE	FALSE	3,305
May	5,408	-	2,534	9,845	shoulder	FALSE	FALSE	FALSE	5,408
Jun	5,170	4,752	4,524	9,845	summer	FALSE	FALSE	FALSE	5,170
Jul	5,551	4,886	4,006	9,845	summer	FALSE	FALSE	FALSE	5,551
Aug	8,256	5,015	4,586	9,845	summer	FALSE	FALSE	FALSE	8,256
Sep	5,649	-	1,703	9,845	shoulder	FALSE	FALSE	FALSE	5,649
Oct	-	-	-	9,845	shoulder	FALSE	FALSE	FALSE	-
Nov	6,882	-	4,234	9,845	shoulder	FALSE	FALSE	FALSE	6,882
Dec	7,053	8,770	6,966	9,845	winter	TRUE	FALSE	FALSE	8,770

The table is used to determine which need signal – satisfying annual or seasonal LOLEV, or Peak VaR – will be used in each month. With the logic columns of TRUE/FALSE indicating whether seasonal frequency MW is larger than annual frequency MW, which month has the highest monthly Peak VaR and therefore should be linked with the Annual Peak VaR, and is the Annual Peak VaR in the selected month larger than both the annual and seasonal frequency MWs. The equations below describe the selection logic for the need in each month.

$$\text{Is Seasonal}_{\text{F}} > \text{Annual_F}_i = \begin{cases} \text{TRUE}, & \text{if Seasaonl Frequency}_{\text{i}} > \text{Annual Frequency}_{\text{i}} \\ \text{FALSE}, & \text{otherwise} \end{cases}$$

$$\text{Is Highest Monthly Peak VaR}_{\text{i}} = \begin{cases} \text{TRUE}, & \text{if Monthly Peak VaR}_{\text{i}} = \text{Max(Monthly Peak VaR)} \\ \text{FALSE}, & \text{otherwise} \end{cases}$$

$$\text{Is Annual VaR largest?}_{\text{i}} = \begin{cases} \text{TRUE}, & \text{if Annual Peak VaR}_{\text{i}} > \text{Seasonal_F and Annual_F} \\ \text{FALSE}, & \text{otherwise} \end{cases}$$

$$\text{Monthly Need}_i = \begin{cases} \text{Annual_F}_i, & \text{if Seasonal_F}_i \; is \; FALSE \text{ and Annual VaR FALSE} \\ \text{Seasonal_F}_i, & \text{if Seasonal_F}_i \; is \; TRUE \text{ and Annual VaR FALSE} \\ \text{Annual_Peak_VaR}, & \text{otherwise} \end{cases}$$

Following the selection logic, each month is further broken down for the peak hour-month capacity shortfall from the shortfall record. Months whose need signal is driven by either the seasonal LOLEV or the annual Peak VaR have all hours superimposed by the larger value (in the example, all of January is superimposed with the Peak VaR and December the Winter with the LOLEV frequency signal), as seen in Table M - 2. The shortfall record uses the specific hourly level data of each shortfall event to know the peak need in every hour in every month just from the events that need to be mitigated.

Table M - 2: Peak Hour-Month MW of the Implied Need to Satisfy LOLEV & Peak VaR

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	9,845	5,256	504	3,289	4,760	4,425	2,575	3,267	-	-	-	8,770
1	9,845	3,555	111	1,858	4,690	1,877	1,159	1,343	-	-	-	8,770
2	9,845	2,960	111	1,850	1,246	2,370	1,050	447	-	-	-	8,770
3	9,845	3,158	118	2,003	1,544	1,926	571	1,481	-	-	441	8,770
4	9,845	3,827	171	1,988	2,075	2,001	1,138	1,505	-	-	1,069	8,770
5	9,845	5,044	298	2,112	2,500	2,720	1,531	1,046	-	-	1,452	8,770
6	9,845	6,836	642	2,192	1,954	2,821	2,795	2,621	117	-	4,400	8,770
7	9,845	8,013	1,198	2,210	2,367	3,212	2,807	2,030	-	-	6,228	8,770
8	9,845	8,116	1,361	2,174	2,968	4,285	3,203	2,865	-	-	6,882	8,770
9	9,845	8,270	868	2,115	3,389	3,907	2,734	3,186	-	-	6,340	8,770
10	9,845	7,637	1,218	2,086	2,208	2,744	3,296	2,096	244	-	3,423	8,770
11	9,845	5,429	578	2,074	2,323	2,284	3,073	3,998	168	-	2,591	8,770
12	9,845	4,170	279	2,069	1,882	2,847	2,766	4,610	404	-	1,068	8,770
13	9,845	4,429	946	2,064	1,792	2,446	3,472	5,303	1,767	-	1,435	8,770
14	9,845	3,080	623	2,051	1,986	2,316	3,664	6,019	2,778	-	1,004	8,770
15	9,845	3,576	808	2,045	1,785	3,017	4,092	6,273	3,266	-	1,167	8,770
16	9,845	4,531	1,018	2,065	2,236	3,589	4,808	7,626	4,548	-	2,560	8,770
17	9,845	7,216	542	2,090	3,870	4,752	5,551	7,664	5,302	-	4,363	8,770
18	9,845	6,944	635	2,220	4,574	4,552	5,296	8,256	5,649	-	4,620	8,770
19	9,845	7,324	1,304	2,378	5,408	5,170	5,367	7,501	4,791	-	3,848	8,770
20	9,845	7,637	1,482	2,663	3,233	4,842	4,642	5,935	3,242	-	2,920	8,770
21	9,845	6,071	102	3,305	1,549	3,618	3,607	3,180	2,087	-	1,799	8,770
22	9,845	3,329	-	1,996	1,949	2,675	1,941	-	529	-	1,260	8,770
23	9,845	4,162	1,120	-	807	2,090	-	-	381	-	-	8,770

Next, the analysis needs to net out the simulated balancing up reserves that GENESYS holds to account for forecast error, otherwise it may be double counted in OptGen. Table M - 3 provides the balancing up reserve example, with each month holding a constant reserve requirement on all hours.

Table M - 3: Example of Monthly Balancing Reserves Held on Every Hour (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Balancing Up Reserves (MW)	2,220	2,411	1,781	1,832	1,845	1,651	1,507	1,497	1,755	1,927	1,927	1,811

The resulting subtraction of balancing up reserves from the implied need may result in negative numbers in some hours – this is not wrong, rather means the balancing reserves would be sufficient to handle the deficit event – and in those hours the new assumed value is zero, as seen in Table M - 4.

Table M - 4: Net Implied Need (MW) to Satisfy LOLEV & Peak VaR 97.5th Percentile

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	7,625	2,845	-	1,457	2,915	2,774	1,068	1,770	-	-	-	6,959
1	7,625	1,144	-	26	2,845	226	-	-	-	-	-	6,959
2	7,625	549	-	18	-	719	-	-	-	-	-	6,959
3	7,625	747	-	171	-	275	-	-	-	-	-	6,959
4	7,625	1,416	-	156	230	350	-	8	-	-	-	6,959
5	7,625	2,633	-	280	655	1,069	24	-	-	-	-	6,959
6	7,625	4,425	-	360	109	1,170	1,288	1,124	-	-	2,473	6,959
7	7,625	5,602	-	378	522	1,561	1,300	533	-	-	4,301	6,959
8	7,625	5,705	-	342	1,123	2,634	1,696	1,368	-	-	4,955	6,959
9	7,625	5,859	-	283	1,544	2,256	1,227	1,689	-	-	4,413	6,959
10	7,625	5,226	-	254	363	1,093	1,789	599	-	-	1,496	6,959
11	7,625	3,018	-	242	478	633	1,566	2,501	-	-	664	6,959
12	7,625	1,759	-	237	37	1,196	1,259	3,113	-	-	-	6,959
13	7,625	2,018	-	232	-	795	1,965	3,806	12	-	-	6,959
14	7,625	669	-	219	141	665	2,157	4,522	1,023	-	-	6,959
15	7,625	1,165	-	213	-	1,366	2,585	4,776	1,511	-	-	6,959
16	7,625	2,120	-	233	391	1,938	3,301	6,129	2,793	-	633	6,959
17	7,625	4,805	-	258	2,025	3,101	4,044	6,167	3,547	-	2,436	6,959
18	7,625	4,533	-	388	2,729	2,901	3,789	6,759	3,894	-	2,693	6,959
19	7,625	4,913	-	546	3,563	3,519	3,860	6,004	3,036	-	1,921	6,959
20	7,625	5,226	-	831	1,388	3,191	3,135	4,438	1,487	-	993	6,959
21	7,625	3,660	-	1,473	-	1,967	2,100	1,683	332	-	-	6,959
22	7,625	918	-	164	104	1,024	434	-	-	-	-	6,959
23	7,625	1,751	-	-	-	439	-	-	-	-	-	6,959

The final step to isolate the need from GENESYS is to align the temporal scale with that of OptGen. OptGen is set up to simulate the power system by distinct periods. Staff evaluated the optimal configuration for result convergence and run time and determined that dividing the months to 6 groups throughout the year (instead of using 12 groups, one for each month) is ideal. In that configuration, the groups included Jan-Feb, Mar-Apr, May-Jun, Jul-Aug-Sep, Oct-Nov, and Dec. Though Dec is a winter month, OptGen is not able to group non-consecutive months, and the simulation starts in January. Based on these groupings, the maximum of each month is used as the final need (MW) to satisfy the adequacy metrics, such as the one seen in Table M - 5 (Dec is considered with Jan and Feb). Each study has its own unique need results.

Table M - 5: Example Need Signal From GENESYS

Season	Need (MW)
Jan/Feb	7,625
Mar/Apr	1,473
May/Jun	3,563
Jul/Aug/Sep	6,759
Oct/Nov	4,955
Dec	7,625

OptGen Load Resource Balance

Developing the PRM for peak capacity requires not only the need signal from GENESYS but also the LRB of the existing system, while making sure the temperature-sensitive extreme conditions are protected against.

All needs assessment studies share the same existing system capability and temperature-sensitive extreme conditions as they share assumptions on load pathway and existing in-region resources. This is shown in the example in Table M - 6, including the GENESYS average seasonal peak load, the OptGen seasonal peak load, and the capability of the hydro, thermal, battery, wind & solar, and market to calculate the total resources ($TR_i = \sum_i Resource_Type_j$).[8]

Table M - 6: Shared Load & Resource Assumptions in OptGen Across Sensitivities

Season	GENESYS Average Seasonal Peak Loads (MW)	OptGen Seasonal Peak Loads (MW)	Avg 2-hr Sustained Peaking Hydro (MW)	Ther-mal (MW)	Battery (MW)	Wind & Solar (MW)	Market (MW)	Total Resources (MW)	Load Re-source Balance
Jan/Feb	42,868	38,096	15,977	12,213	1,160	3,155	6,100	38,604	-4,264
Mar/Apr	35,975	32,429	16,441	12,213	1,160	4,063	4,850	38,727	2,753
May/Jun	36,813	32,357	18,811	12,213	1,160	4,143	4,850	41,177	4,364
Jul/Aug/Sep	40,541	34,826	15,035	12,213	1,160	5,418	4,850	38,675	-1,866
Oct/Nov	37,933	32,366	11,003	12,213	1,160	3,306	6,100	33,782	-4,151
Dec	41,246	36,453	12,946	12,213	1,160	2,296	6,100	34,715	-6,531

The total resources in each season is the sum of each type of resource, and the LRB is the difference between the GENESYS average seasonal load and the total seasonal resource. A negative LRB

[8] The assumed market capability is the total allowed sum-of-circuit transfer throughout the region. This number assumes the market reliance limit is met: 2,500 MW in winter and 1,250 MW in summer.

indicates the season is short. There is no consideration of need at this point, and the fact that the season is short is solely driven by the expected load growth in the future year (2031). Additionally, note that the GENESYS peak load is higher than the OptGen peak load. This is due to GENESYS seeing a full set of temperature informed loads, whereas OptGen uses a typical day load.

Developing Final Peak Planning Reserve Margin

For simplicity in the following tables the seasonal resource breakdowns are removed to focus on the connection to resource need and development of the PRM, illustrated in Table M - 7, with the equations used below. The need column (N) is the same need as developed in the section above.

Table M - 7: Development of Planning Reserve Margin for Peak Capacity

Season	GL **GENESYS Average Peak Loads (MW)**	OL **OptGen Peak Loads (MW)**	TR **Total Resources (MW)**	N **Need (MW)**	LRB **Load Resource Balance (MW)**	AM **Eq1 Adequacy Margin**	SPCR **Eq2 Seasonal Peaking Margin + Contingency Reserves**	PRM **Eq3 Planning Reserve Margin (PRM)**
Jan/Feb	42,868	38,096	38,604	7,625	-4,264	7.8%	19.3%	28.6%
Mar/Apr	35,975	32,429	38,727	1,473	2,753	11.7%	17.6%	17.6%
May/Jun	36,813	32,357	41,177	3,563	4,364	21.5%	20.6%	20.6%
Jul/Aug/Sep	40,541	34,826	38,675	6,759	-1,866	12.1%	23.4%	38.3%
Oct/Nov	37,933	32,366	33,782	4,955	-4,151	2.1%	24.2%	26.9%
Dec	41,246	36,453	34,715	7,625	-6,531	2.7%	19.9%	23.1%

Eq (1):

$$\mathrm{AM}_i = \begin{cases} \frac{\mathrm{TR_i + N_i - LRB_i - GL_i}}{\mathrm{GL_i}}, & \text{if } \mathrm{LRB_i} > 0 \text{ and } N_i > LRB_i \\ \frac{\mathrm{TR_i + N_i - GL_i}}{\mathrm{GL_i}}, & \text{otherwise} \end{cases}$$

Eq (2):

$$\mathrm{SPCR}_i = \left(\frac{\mathrm{GL_i}}{\mathrm{OL_i}}\right) x\,(1.06) - 1$$

Eq (3):

$$\mathrm{PRM}_i = \left[\left(1 + \begin{cases} \mathrm{AM}_i, & \text{if } \mathrm{AM}_i > 0 \text{ and } \mathrm{LRB}_i < 0 \\ \mathrm{AM}_i, & \text{if } \mathrm{AM}_i > 0 \text{ and } \mathrm{Need}_i > \mathrm{LRB}_i \\ 0, & \text{otherwise} \end{cases}\right) \times \left(\frac{\mathrm{GL_i}}{\mathrm{OL_i}}\right) x\,(1.06) - 1\right]$$

Following the three equations helps to understand the PRM process. First, in Eq1 the adequacy margin (AM) is calculated for each period i as the percentage above GENESYS peak load that the LRB and need account for. Second, as mentioned before, as GENESYS observes larger loads, OptGen needs to account for this seasonal peaking margin, which is separate from the need. In Eq2, this takes place, and a contingency of 6% is included to account for the load and generation contingency risk.

Eq3 then integrates the AM and seasonal peaking margin and contingency reserves (SPCR) into the final PRM calculation for each season and defines the percent above load that OptGen must satisfy to meet peak capacity from the existing and new resource strategy. Here, it is important to understand

that the need is driven by the higher loads, and the methodology should avoid double counting the impact of higher loads. In this example, notice that as the LRB is positive in Mar/Apr and May/Jun, the SPCR and PRM values are the same – indicating that load growth alone is explains the increase in reserve margins, as opposed to other seasons with negative LRB, and the adequacy need is also a component and resulting in higher PRMs.

Energy – Adequacy Reserve Margin

The process to determine the energy ARM – or firm energy – that OptGen requires relies on the implied need to satisfy the Duration and Energy VaR 97.5th percentiles. Determining this value requires evaluating and manipulating the shortfall record until the metrics are satisfied.

Mitigating Annual Duration VaR 97.5th Percentile Risk

The duration metric is a tail-end statistic of the distribution of longest shortfall durations with the adequacy threshold of 8-hours. As you add more resources to a deficit, system duration VaR is lowered until reaching the allowed limit of 8 hours. Determining how many resources are needed requires iterations of resource additions through post-processing of the shortfall record and rerunning the adequacy analysis until the Duration VaR is satisfied.

Consider the example in Table M - 8 representing a 17-hour long shortfall from one illustrative simulation year that occurred on Feb 10th. In the first iteration 1,000 aMW were added, and every shortfall hour was subtracted by 1,000, and in the second an additional 500 aMW for a total of 1,500 aMW were added. Notice that the 17-hour event became smaller, shorter events.

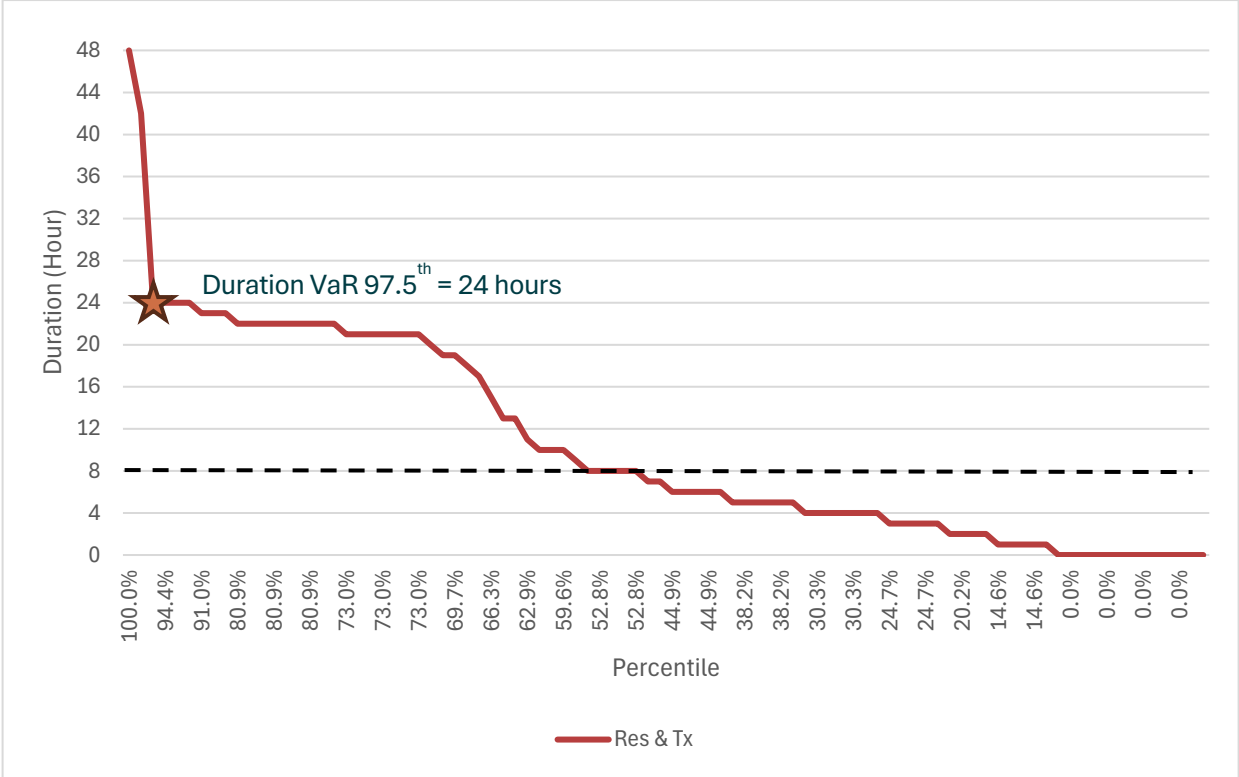
Table M - 8: Illustrative Example for Process to Satisfy Duration VaR

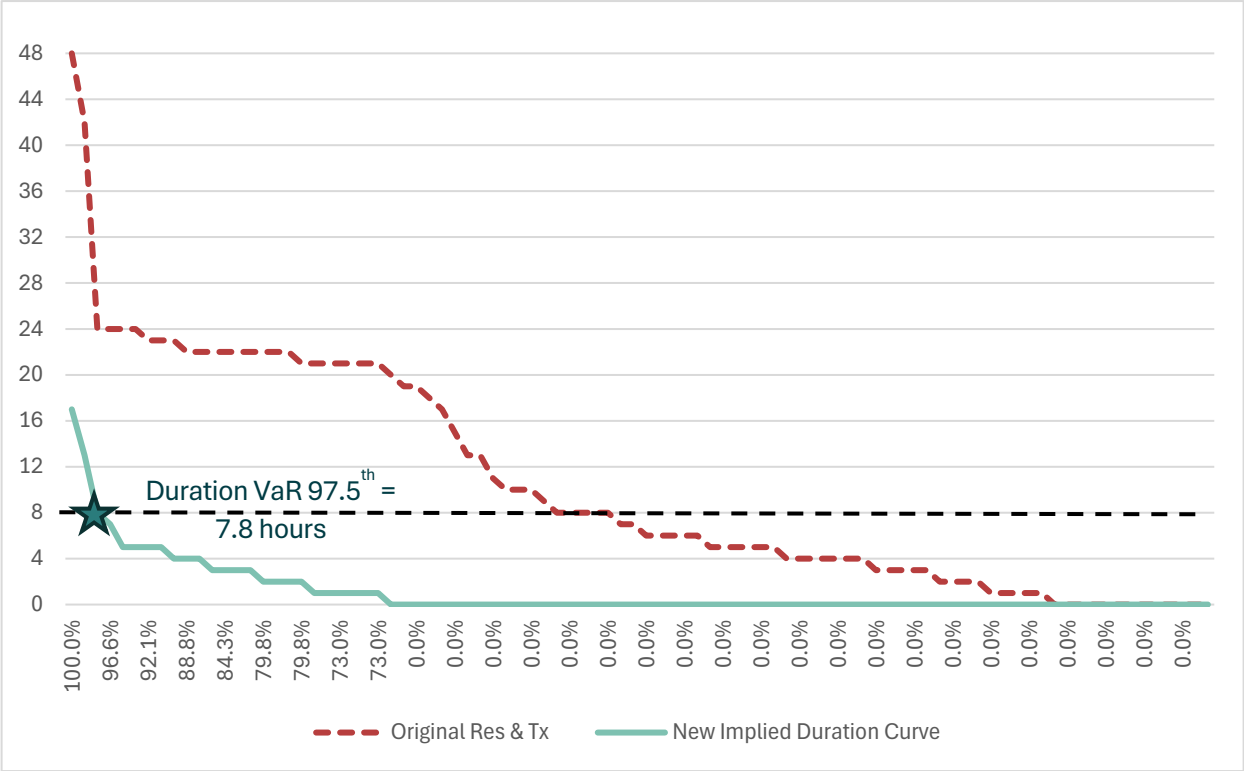
Simulation Date	Original Shortfall (MW)	Firm Energy Addition: Adding 1000 aMW (remaining shortfall MW)	Firm Energy Addition: Adding 1,500 aMW (remaining shortfall MW)
Feb-10 5am	751	0	0
Feb-10 6am	3,836	2,836	2,336
Feb-10 7am	4,572	3,572	3,072
Feb-10 8am	4,889	3,889	3,389
Feb-10 9am	2,824	1,824	1,324
Feb-10 10am	2,880	1,880	1,380
Feb-10 11am	1,331	331	0
Feb-10 12pm	1,876	876	376
Feb-10 1pm	1,278	278	0
Feb-10 2pm	127	0	0
Feb-10 3pm	1,701	701	201
Feb-10 4pm	1,256	256	0
Feb-10 5pm	3,719	2,719	2,219
Feb-10 6pm	3,715	2,715	2,215
Feb-10 7pm	4,256	3,256	2,756
Feb-10 8pm	2,298	1,298	798
Feb-10 9pm	3,422	2,422	1,922
# of Events	1	2	4
Max Duration	17	8	5

The full methodology does not require observing every single shortfall. Rather, the adequacy analysis focuses on the 97.5th percentile of the new maximum duration shortfalls from each iteration. When the Duration VaR 97.5 value drops to (or closest below) 8, the process stops and the firm energy used is recorded.

Figure M - 4 shows an example from an original shortfall curve (top) and the new implied duration curve (bottom) after adding enough aMW to reach the Duration VaR 97.5th percentile value just below 8.

Figure M - 4: Maximum Duration Curve Example

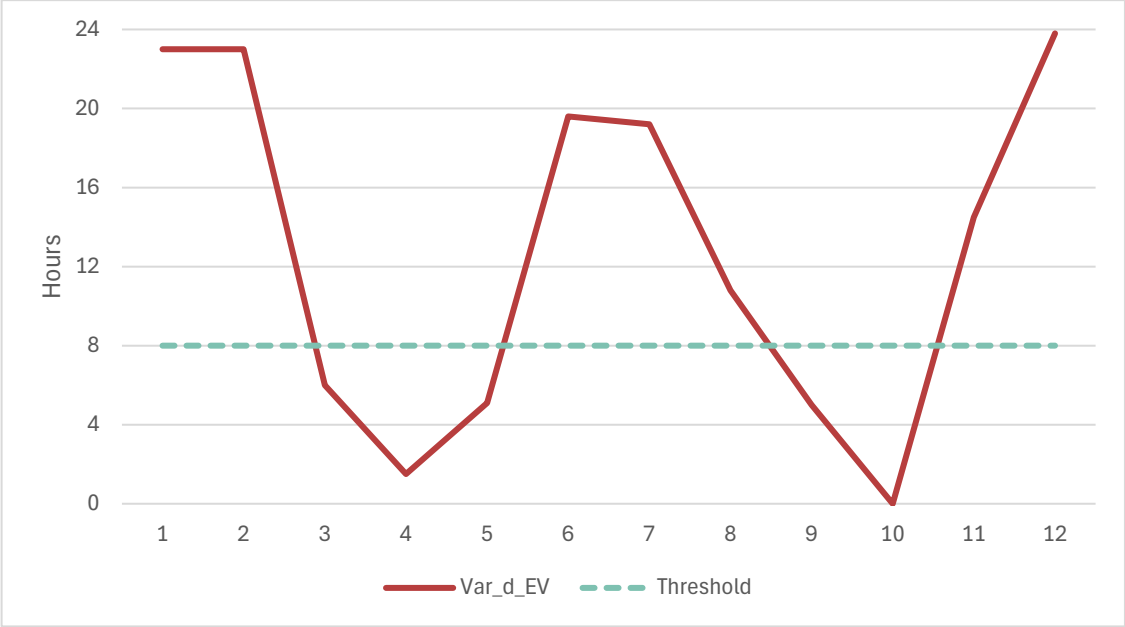




Developing Final Energy Adequacy Reserve Margin

In the example above, the firm energy needed to satisfy the Duration VaR was 5,900 aMW. This value is compared to the Energy VaR 97.5th percentile value, and if it is larger than the aMW implied to satisfy energy VaR (Energy VaR value minus the threshold), then the value to satisfy the Duration VaR is used. For example, if the Energy VaR 97.5th percentile is 880,638 MWh (Table M - 13), the implied firm energy throughout the year to mitigate it is 871,038 MWh (888,638 - 9,600), and dividing by 8,760 hours results in a firm energy of 99.4 aMW, lower than the implied firm energy to satisfy Duration VaR. Similar to Peak VaR, it's important to understand the months that exhibit the long duration risks ,as seen in the monthly duration VaR in Figure M - 5.

Figure M - 5: Monthly Duration VaR 97.5th Percentile



In the example, winter and summer experience the highest risk of long durations, and serve as the signal for which to base the annual firm energy on. The next step is to determine what percent above load does this aMW represent in each month that surpasses the threshold, seen in Table M - 9.

Table M - 9: Energy ARM Development

Month	Monthly Duration VaR	Threshold	Firm Energy Adjustment (aMW)	GENESYS Avg Monthly Load	Monthly Energy ARM	Annual Energy ARM
Jan	23	8	5,900	34,506	17%	Max of monthly (20%)
Feb	23	8	5,900	33,001	18%	
Mar	6	8	-	30,182	0%	
Apr	1.5	8	-	28,108	0%	
May	5.1	8	-	27,631	0%	
Jun	19.6	8	5,900	29,073	20%	
Jul	19.2	8	5,900	30,890	19%	
Aug	10.8	8	5,900	30,679	19%	
Sep	5	8	-	27,851	0%	
Oct	0	8	-	27,724	0%	
Nov	14.5	8	5,900	31,066	19%	
Dec	23.8	8	5,900	33,870	17%	

$$\text{Annual EnergyARM}_{\text{i}} = \text{Max}\left(\frac{\text{FirmEnergy}_{\text{i}}}{\text{AverageLoad}_{\text{i}}}\right)$$

The final step is to take the maximum percentage and apply that as the annual percentage needed to be held across the years. This percent is then multiplied by the annual load, and OptGen must ensure sufficient firm energy is available every month for it.

Reminder of the Existing System and Data Assumption

The needs assessment is a forward look into the region's power supply in 2031. As such, the need, gap in resources for the region to be adequate, is related to the load growth pathway as well as what resources are existing as of May of 2025. For a full description of the existing system assumed in the Ninth Plan, see Technical Appendix B – Existing System Parameters and Policies.

For the needs assessment, the Council used the electricity demand from the high growth pathway in 2031. This pathway was chosen to ensure the plan strategy will be adequate under all plan futures. For a full description of the load forecasts, see Technical Appendix F – Electricity Demand Forecast.

Two other assumptions play a large role in the needs assessment. First, transmission and wholesale market availability assumptions. GENESYS uses a representative transmission topology on a balancing authority (BA) spatial level for in-region and out-of-region BAs with their allowed transfer (transmission) capabilities. For the Ninth Plan, the Council's modeling is aligned as much as possible with the results of the Western Transmission Expansion Coalition (WestTEC) 10-year study. [9] For the

[9] WestTEC is the Western Transmission Expansion Coalition, a west-wide voluntary effort to conduct long-term transmission planning for the west. The 10-year study is available at: https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition.

wholesale market availability, GENESYS relies on the results of market study (Figure M - 1) to provide the out-of-region resources for the market fundamental component that influences the export and import dynamics in the model. For a full description of the market assumptions, see Technical Appendix L – Wholesale Market Availability Results.

Second, the Council uses climate-informed future projections for temperature-sensitive stream flows and loads. These are based on the data developed by the River Management Joint Operating Committee (RMJOC) that the Council has used in the 2021 Power Plan.[10] For the Ninth Plan, staff further enhanced the climate-informed modeling of wind generation and solar generation in the region, which is also aligned with the coincident temperature-sensitive conditions of stream flows and loads. For a full description of the climate data assumptions see Technical Appendix D - Climate Model Data and Assumptions, as well as Technical Appendix G – New Generating Resource for description of solar and wind generation assumptions.

Tested Sensitivities

This section is meant to briefly list the five tested sensitivities that are the core of the Ninth Plan needs assessment. These include four changes to hydro operation (Hydro Op) studies and one resource and transmission risk (Res & Tx). A detailed account is provided in Technical Appendix N – Scenario Modeling and Results.

Changing Hydro Operations Studies

The Hydro Op studies test the intersection between hydro system operations and adequacy needs to develop new resources in the future. The changing operations are related to the spill and reservoir operation of the four Lower Snake projects (Lower Granite, Little Goose, Lower Monumental, and Ice Harbor) and the four Lower Columbia projects (McNary, John Day, the Dalles, and Bonneville).

The timing of the needs assessment for the Ninth Plan aligned with the development of the Council's Fish and Wildlife Program and allowed an unique opportunity to evaluate the resource need implications to help inform the program.[11] To that end, the four sensitivities covered a range of

[10] See "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

[11] Under the Northwest Power Act, the Council is required to develop a Fish and Wildlife Program to protect, mitigate, and enhance the fish and wildlife affected by the development and operation of any hydroelectric project in the region. The Program is also expected to establish objectives for the development and operation of such projects in the region in a manned designed to protect, mitigate, and enhance fish and wildlife [§4(h)(2)(A), 94 Stat. 2708]. The Northwest Power Act also calls on the Council to "set forth a general scheme for implementing conservation measures and developing resources … to reduce or meet the Administrators obligations" [§4(e)(2), 94 Stat. 2708]. These obligations include Bonneville's obligations to implement the Council's Fish and Wildlife Program. Therefore, the Act intended that there would be some deration of the system for the benefit of fish and wildlife, and it is the task of the power plan to make up any resulting power needs.

operations selected in response to recommendations from the 2021 Power Plan and the 2026 Fish and Wildlife Program amendment process. The four sensitivities are described in Table M - 10.

Table M - 10: Changing Hydro Operations Scenario Scope

Sensitivity	Description
2020 BiOp Flex Spill Operation	Assumes the operations based on the 2020 Columbia River System Operations Environmental Impact Statement. This sensitivity was intended to provide one end of the bounds for potential 2026 operations, based on the assumption that legally, until another agreement was in place, the system should revert to these operations.
2023 RCBA Operations	Assumes the operations as defined in the 2023 Resilient Columbia Basin Agreement. This sensitivity was intended to provide an alternative set of operations with a focus on steady spill throughout the spring, acting as a potential bookend to the range of uncertainty round 2026 operations.
Recommended Spill and MOP Targets	Analyzed specific minimum operating pool elevations and limits and spill operations, as recommended by some of the states and tribes into the Fish and Wildlife Program amendment process. This sensitivity was intended to provide insights on potential hydropower system impacts of those specific recommendations.
Limited Flex Operation	Analyzed limitations of the hydro systems ability to change daily elevations and outflows at the lower Columbia and lower Snake River projects. This was intended to inform on the hydropower system implications of limiting the daily flexibility of the system.

Determining the Hourly Ramping Limitation for the Limited Flex Sensitivity

One of the outcomes of the 2021 Power Plan was to highlight the benefits of leaning into the flexibility (hourly or daily fluctuations) of the hydro system for power generation and reserves. However, the Council's 2014 Fish and Wildlife Program contains measures calling on the system to minimize or reduce daily fluctuations (i.e. flexibility) and several entities submitted recommendations and comments into this amendment process calling on recommendations to reduce flow fluctuations. To provide insight into the implications of limiting the flexibility of the Lower Snake and Lower Columbia projects, the Limited Flex sensitivity was developed.

GENESYS sees more operational flexibility on a daily basis, while meeting all the existing constraints, than is currently being utilized in today's actual operations. As such, the guiding principle of this sensitivity is to limit the model's ability to flex the eight lower projects akin to current system dynamics on the daily range of outflows at these projects.

Recognizing the model sees more flexibility than is used in actual operations, the Council set flexibility limits based on 2020-2024 changes in elevations and flows. These years were chosen due to alignment with BiOp operations, as well as years with RCBA operations. The process to mimic the daily operations starts by calculating the daily range of outflows (the difference between the

maximum hourly outflow and minimum hourly outflow in a calendar day) for each project in day, starting Jan 1st 2020 and ending December 31st 2024[12]. Then, the monthly average of daily outflow fluctuations is developed, seen in Table M - 11 as a tradeoff in seasonal monthly variation.

Table M - 11: Average Daily Range of Outflows 2020-2024 (kcfs/day)

Month	LWG	LGS	LMN	IHR	MCN	JDA	TDA	BON
Jan	29.7	33.8	34.0	32.7	47.5	58.4	63.5	33.1
Feb	32.6	32.9	34.0	33.0	49.4	55.3	57.8	32.4
Mar	31.4	32.1	31.1	28.3	58.7	59.6	59.0	20.4
Apr	8.8	11.3	14.4	14.0	26.3	34.7	42.2	14.8
May	15.5	18.6	32.0	24.7	25.3	43.0	45.4	28.3
Jun	16.1	21.3	28.5	24.8	36.3	45.7	48.5	27.5
Jul	14.0	18.7	16.8	19.5	48.0	68.9	66.7	31.7
Aug	10.7	13.0	12.2	16.6	40.2	65.0	66.6	32.6
Sep	19.2	19.5	18.8	21.0	42.3	43.3	43.3	24.8
Oct	15.0	14.2	14.6	15.8	42.2	38.3	38.6	24.6
Nov	19.2	18.4	18.4	19.0	59.1	53.9	55.6	29.3
Dec	25.0	25.3	26.3	26.6	48.0	45.4	57.7	38.3
Average kcfs/day	**19.7**	**21.6**	**23.4**	**23.0**	**43.6**	**51.0**	**53.8**	**28.1**
Average cfs/day	19,708	21,555	23,376	22,974	43,599	51,004	53,780	28,145
Average cfs/min	13.7	15.0	16.2	16.0	30.3	35.4	37.3	19.5
Adjusted cfs/min	16	16	16	16	40	40	40	40
Adjusted kcfs/hr	0.96	0.96	0.96	0.96	2.4	2.4	2.4	2.4
WMP Appendix 2 kcfs/hr	70	70	70	20	150	200	150	25[13]
Adj Limit % of WMP	1.37%	1.37%	1.37%	4.80%	1.60%	1.20%	1.60%	9.60%

As very tight ramping bounds were too challenging to model, the Council ultimately relied on the average daily outflow fluctuation as the representative flexibility limitation for each project. These outflow ranges of thousands of cubic feet per second (kcfs) per day then need to be converted into cubic feet per second (cfs) per minute, the parameter utilized in GENESYS to control for outflow discharge. Table M - 11 also provides the modeled cfs/min ramping rates for each project ("adjusted cfs/min" in the table). The final rates are slightly higher than the average ranges due to enabling slightly more modeling slack and to ensure GENESYS was able to simulate. Also in Table M - 11 are the allowed kcfs/hr ramping of the Lower Snake and Lower Columbia projects in Water Management Plan Appendix 2.[14] One reason GENESYS utilizes more ramping flexibility is specifically because Appendix 2 allows these ramp rates, though actual ramping operations are more narrow in real world operations.

[12] US Army Corps of Engineers Dataquery 2.0 https://www.nwd-wc.usace.army.mil/dd/common/dataquery/www.
[13] Bonneville's 25 kcfs/hr outflow ramp rates is based on tailrace operations.
[14] 2026 Water Management Plan Appendix 2 https://public.crohms.org/tmt/documents/wmp/2026/Appendix/Appendix_2_2026_Project_Data_20250731.pdf.

Resource & Transmission Risk

The New Resource and Transmission Risk (Res & Tx) scenario sensitivities test different power system characteristics under the hydro operations outlined in the Draft 2026 Columbia River Basin Fish and Wildlife Program.[15] High-level, these include (1) spring spill as defined in 2023 RCBA of 24 hour 125% total dissolved gas (TDS) and summer performance spill end date of August 1st (Lower Snake) and August 15th (Lower Columbia), (2) limiting the flexibility (daily ramping) of the Lower Columbia and Lower Snake projects during the migration season of April-August to minimize the impact on migratory fish populations, and (3) no change to pool elevation operations from the ones described in the 2020 Biological Opinion.[16] The tested sensitivities are described in Table M - 12. While there are several sensitivities, they all share the same underlying existing system, and therefore the same needs assessment study and PRM and ARM signals.[17]

Table M - 12: New Resource and Transmission Risk Sensitivities

Sensitivity	Description
Constrained Resources and Transmission	Constrains supply-side resources in the near-term (first 6 years), limits transmission to the existing system, and delays emerging technologies by 10 years. Sensitivity will inform how the region maintains adequacy when the system is constrained on the supply-side.
Changing Transmission Availability	Includes three sensitivities with different levels of transmission development: existing transmission, transmission consistent with the WestTEC 10-year study, and additional transmission.[18] Sensitivities will inform how resource decisions change with more or less transmission availability.
Changing Emerging Technology Costs	Includes two sensitivities with different cost assumptions for emerging technologies: 25 percent lower costs and 50 percent higher costs. Sensitivities will provide insight on at what costs different emerging technologies might provide value to the system.
Limited Short-Duration Storage Availability	Constrains the availability of short-duration (lithium ion) battery storage in the near-term (first 6 years). Sensitivity will provide insights into the potential value of short-duration storage to the region and how the region will maintain adequacy if that resource is not available.

[15] See Draft Fish & Wildlife Program measures.
[16] The final 2026 Columbia River Basin Fish and Wildlife Program removed the provision on summer spill, but the other elements remained the same. The Council took this change into account as part of the final adequacy check on the proposed regional resource strategy. See Technical Appendix N – Scenario Modeling Results for more information.
[17] This is since the hydro operations are consistent across these sensitivities, and the need impact due to variation in out-of-region market buildout and transmission availability was expected to not yield significant differences; at the expense of substantially more modeling time.
[18] WestTEC is the Western Transmission Expansion Coalition, a west-wide voluntary effort to conduct long-term transmission planning for the west. The 10-year study is available at: https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition.

Sensitivity	Description
Slower Demand-Side Availability	Slows down the pace of potential demand-side resource acquisition, including conservation, demand response, and rooftop solar. Sensitivity will provide insights on how the system maintains adequacy if less demand-side resources are available in the near-term.
Evolving Federal Policy Landscape	Assumes a change in Federal policy 2030, shifting to policies similar to Biden-era policies. Sensitivity provides insights on how resource decisions change in the region with changes in policies at the federal level.

Needs Assessment Results

The results show a significant regional resource need in 2031 across all studies. Three main takeaways include: there are peak needs in all seasons, particularly in winter and summer, there is an energy signal for summer and winter, and the longest and largest events are in the winter. The main driver for these needs is the expected load growth.

Roughly speaking, all scenarios experience similar large peak tail-risk between 9,300-11,500 MW and long duration shortfalls (ranging from 22 to above 40 hours) as well as many outage events throughout the year. Staff caution from over interpreting or over emphasizing individual study results because they are sensitive to the nuance of translating the shortfall record to the reserve margins.

Table M - 13: Adequacy Criteria Results

	Frequency			Extreme Deficits		
Metric	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
BiOp	6.76	4.58	1.37	23	9,352	543,010
RCBA	8.71	6.04	1.54	22.8	10,128	590,842
MOP Op	10.23	5.32	2.62	44	9,666	912,141
LimFlex	21.33	14.14	3.86	49.5	11,504	2,692,698
Res & Tx	10.50	6.96	2.32	24	11,045	880,638

Figure M - 6 and Figure M - 7 highlight the monthly duration and peak VaRs, showing how winter and summer outages dominate the shortfall risk. The thresholds are included for guiding purposes.

Figure M - 6: Monthly Duration VaR 97.5)

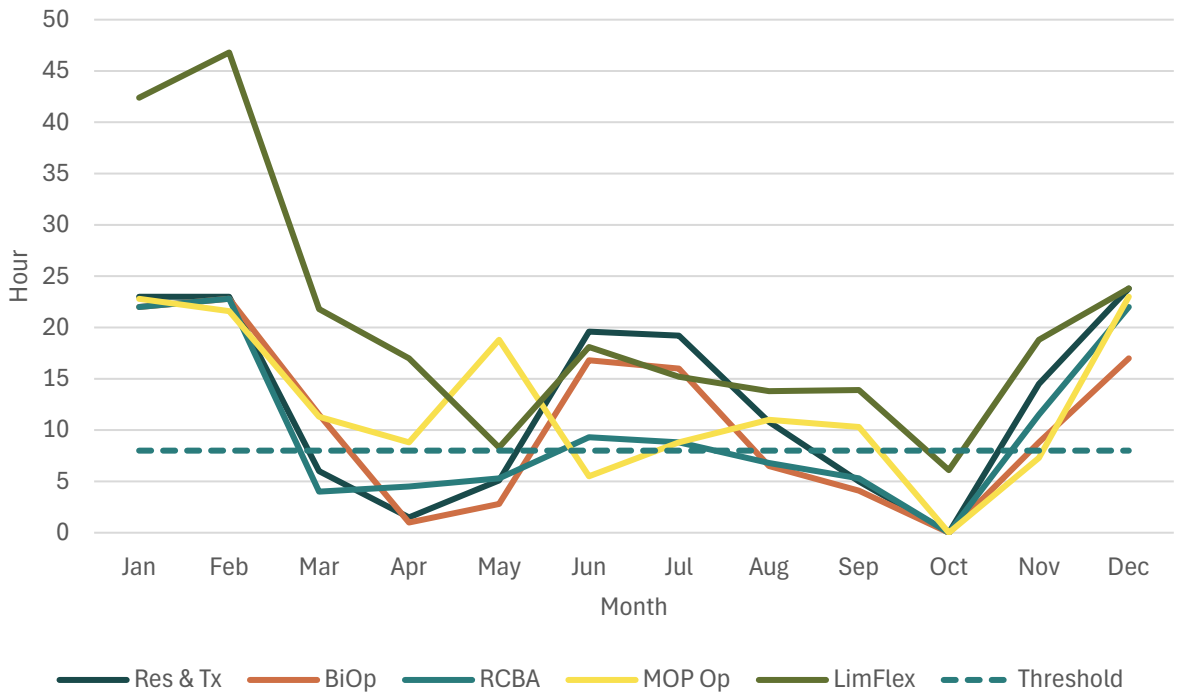
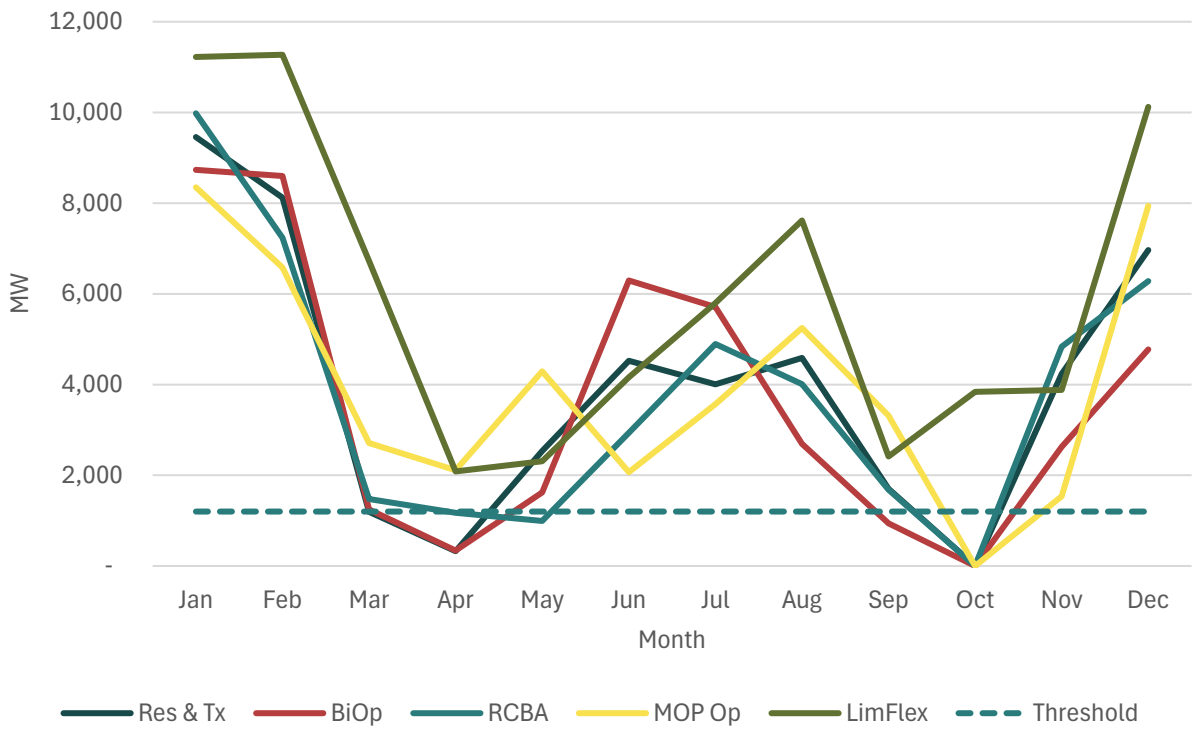


Figure M - 7: Monthly Peak VaR 97.5



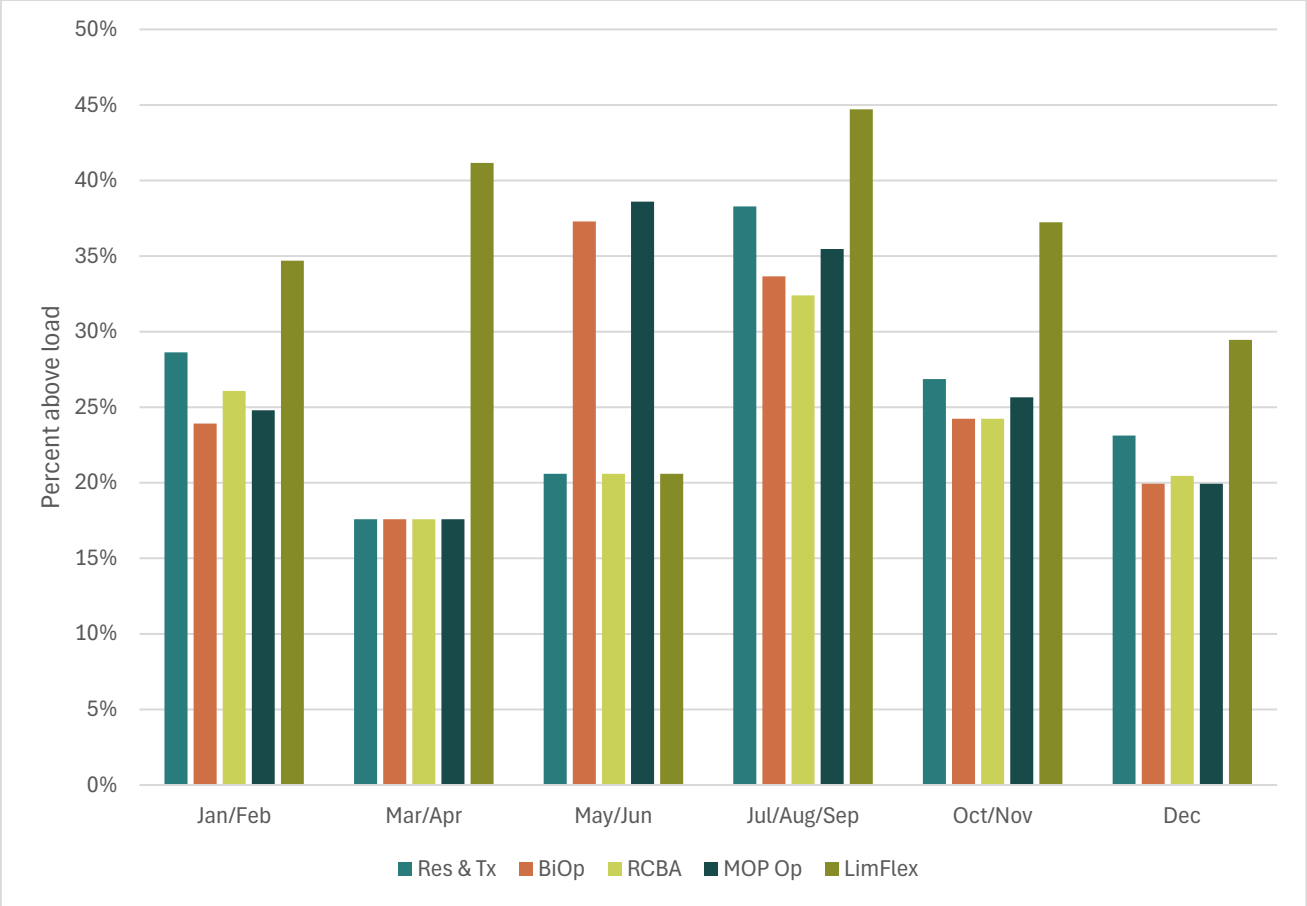
Peak Planning Reserve Margin

The metric values feed into the PRM and ARM as outlined in the methodology section above. The full results are presented in Table M - 14, with Figure M - 8 focusing on the final PRM for each study.

Table M - 14: PRM Calculation

Study	Period	GENESYS Average Peak Loads (MW)	OptGen Peak Loads (MW)	Total Resources (MW)	Need (MW)	Load Resource Balance (MW)	AM Eq1 Adequacy Margin	SPCR Eq2 Seasonal Peaking Margin + Contingency Reserves	PRM Eq3 Planning Reserve Margin (PRM)
Res & Tx	Jan/Feb	42,868	38,096	38,604	7,625	-4,264	7.8%	19.3%	28.6%
	Mar/Apr	35,975	32,429	38,727	1,473	2,753	11.7%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	3,563	4,364	21.5%	20.6%	20.6%
	Jul/Aug/Sep	40,541	34,826	38,675	6,759	-1,866	12.1%	23.4%	38.3%
	Oct/Nov	37,933	32,366	33,782	4,955	-4,151	2.1%	24.2%	26.9%
	Dec	41,246	36,453	34,715	7,625	-6,531	2.7%	19.9%	23.1%
BiOp	Jan/Feb	42,868	38,096	38,604	5,932	-4,264	3.9%	19.3%	23.9%
	Mar/Apr	35,975	32,429	38,727	1,289	2,753	11.2%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	5,095	4,364	13.8%	20.6%	37.3%
	Jul/Aug/Sep	40,541	34,826	38,675	5,239	-1,866	8.3%	23.4%	33.7%
	Oct/Nov	37,933	32,366	33,782	2,969	-4,151	-3.1%	24.2%	24.2%
	Dec	41,246	36,453	34,715	5,932	-6,531	-1.5%	19.9%	19.9%
RCBA	Jan/Feb	42,868	38,096	38,604	6,708	-4,264	5.7%	19.3%	26.1%
	Mar/Apr	35,975	32,429	38,727	1,832	2,753	12.7%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	2,318	4,364	18.2%	20.6%	20.6%
	Jul/Aug/Sep	40,541	34,826	38,675	4,823	-1,866	7.3%	23.4%	32.4%
	Oct/Nov	37,933	32,366	33,782	3,970	-4,151	-0.5%	24.2%	24.2%
	Dec	41,246	36,453	34,715	6,708	-6,531	0.4%	19.9%	20.5%
MOP Op	Jan/Feb	42,868	38,096	38,604	6,246	-4,264	4.6%	19.3%	24.8%
	Mar/Apr	35,975	32,429	38,727	2,717	2,753	15.2%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	5,497	4,364	14.9%	20.6%	38.6%
	Jul/Aug/Sep	40,541	34,826	38,675	5,833	-1,866	9.8%	23.4%	35.5%
	Oct/Nov	37,933	32,366	33,782	4,586	-4,151	1.1%	24.2%	25.7%
	Dec	41,246	36,453	34,715	6,246	-6,531	-0.7%	19.9%	19.9%
LimFlex	Jan/Feb	42,868	38,096	38,604	9,803	-4,264	12.9%	19.3%	34.7%
	Mar/Apr	35,975	32,429	38,727	7,213	2,753	20.1%	17.6%	41.2%
	May/Jun	36,813	32,357	41,177	3,810	4,364	22.2%	20.6%	20.6%
	Jul/Aug/Sep	40,541	34,826	38,675	8,870	-1,866	17.3%	23.4%	44.7%
	Oct/Nov	37,933	32,366	33,782	8,123	-4,151	10.5%	24.2%	37.2%
	Dec	41,246	36,453	34,715	9,803	-6,531	7.9%	19.9%	29.5%

Figure M - 8: Final PRM



Energy Adequacy Reserve Margin

The implied firm energy to satisfy the Duration VaRs ranges between 4,250 to 6,000 aMW across the studies, and all are greater than the implied energy to satisfy the Energy VaR and therefore are used for the firm energy signal. Table M - 15 shows the annual firm energy percent that serve as the ARM in OptGen. This value (in each study) is scaled up and down to be used in other years (the needs assessment focuses on 2031, but OptGen simulates a wider range of years).

Table M - 15: Final Annual ARM

Study	Annual Firm Energy
Res & Tx	20.3%
RCBA	14.6%
BiOp	14.6%
MOP Op	15.5%
LimFlex	20.6%

Technical Appendix N: Scenario Modeling and Results

Contents

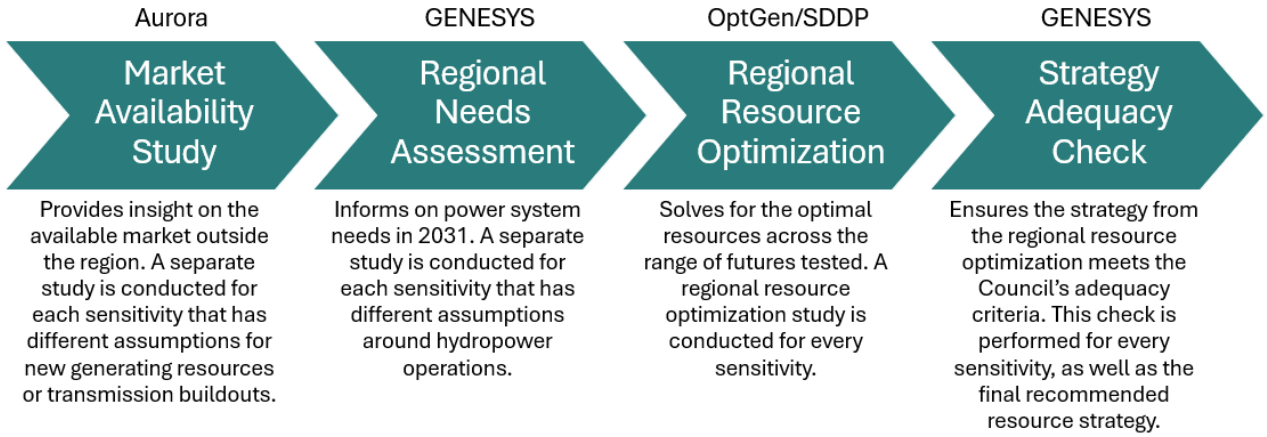
Introduction 1
Description of Ninth Plan Scenarios 2
New Resource and Transmission Risk 2
Changing Hydro Operations 10
Modeling Results 16
Primary Resource Themes 17
Emerging Technology Resource Themes 36
Remaining Resource Themes 39
Market Price Results 40
Emissions 48
Additional Sensitivities 51
Adequacy Check of Proposed Resource Strategy 53
Methodology for Checking Strategy Adequacy 54
The Tested Hydro Conditions 55
Adequacy Check Results 56

Introduction

The Council uses scenario modeling to plan under uncertainty. The scenarios considered in the Ninth Plan were designed to address the key challenges and uncertainties facing the regional power system at the time of power plan development. These include uncertainties around the pace of new resource development, the cost of new resources, the future availability of transmission, and future hydropower operations.

In total, scenario modeling covers a suite of studies providing information on system needs, market availability, regional resource optimization, and ensuring adequacy checks of the resources. Figure N - 1 illustrates the overall scenario modeling approach, including the model used for each step in the analysis.

Figure N - 1: Scenario Modeling Approach for Ninth Plan



This technical appendix focuses on the results from the regional resource optimization and strategy adequacy check steps of the scenario modeling. More information on the overall modeling framework for scenario modeling, as well as results from other stages of analysis can be found in other technical appendices. Specifically:

- **Technical Appendix K – Modeling Framework.** This technical appendix provides more detail on how the modeling suite connects, as well as key decisions around the modeling setup for the Ninth Plan analysis. This includes the development of futures to represent uncertainty around a range of assumptions feeding into modeling, including future loads, natural gas prices and volatility, and fuel availability for hydro, solar, and wind.
- **Technical Appendix L – Wholesale Market Availability Results.** This technical appendix provides more information on specific assumptions required for each of the market availability studies conducted and provides the results from those studies.
- **Technical Appendix M – Needs Assessment Results.** This technical appendix provides more specific information about the GENESYS setup for the modeling of the different sensitivities and walks through the results of the needs assessments for the Ninth Plan.

Description of Ninth Plan Scenarios

Scenario modeling provides an approach for exploring uncertainty around an otherwise deterministic set of assumptions. The Ninth Plan includes two scenarios that have within each of them a suite of sensitivities to explore a range of risk. This section describes the two scenarios and the specific assumptions behind each one.

New Resource and Transmission Risk

The Council's power plans have often included scenarios that explore how resource decisions change with changes in the availability (or pace) of potential resource development. Historically, much of this

analysis focused on the pace of demand-side resource development, particularly conservation. For the Ninth Power Plan, the Council broadened this to include other resources. This scenario also explored implications of different transmission buildout trajectories and changing costs for some new resources. Table N - 1 outlines the sensitivities explored in this scenario and the sections below provide more detail on the specific assumptions changed for each sensitivity.

Table N - 1: New Resource and Transmission Risk Sensitivities

Sensitivity	Description
Constrained Resources and Transmission	Constrains supply-side resources in the near-term (first 6 years), limits transmission to the existing system, and delays emerging technologies by 10 years. Sensitivity informs how the region maintains adequacy when the system is constrained on the supply-side.
Changing Transmission Availability	Includes three sensitivities with different levels of transmission development: existing transmission, transmission consistent with the WestTEC 10-year study, and additional transmission.[1] Sensitivities will inform how resource decisions change with more or less transmission availability.
Changing Emerging Technology Costs	Includes two sensitivities with different cost assumptions for emerging technologies: 25 percent lower costs and 50 percent higher costs. Sensitivities will provide insight on at what costs different emerging technologies might provide value to the system.
Limited Short-Duration Storage Availability	Constrains the availability of short-duration (lithium ion) battery storage in the near-term (first 6 years). Sensitivity will provide insights into the potential value of short-duration storage to the region and how the region will maintain adequacy if that resource is not available.
Slower Demand-Side Availability	Slows down the pace of potential demand-side resource acquisition, including conservation, demand response, and rooftop solar. Sensitivity will provide insights on how the system maintains adequacy if less demand-side resources are available in the near-term.
Evolving Federal Policy Landscape	Assumes a change in Federal policy in 2030, shifting to policies similar to Biden-era policies. Sensitivity provides insights on how resource decisions change in the region with changes in policies at the federal level.

Constrained Resources and Transmission

This sensitivity was developed to address concerns about the availability of new generating resources and transmission. The worldwide Covid pandemic caused supply chain challenges for many goods, including materials for the development of resources. This coincided with a period of increased

[1] WestTEC is the Western Transmission Expansion Coalition, a west-wide voluntary effort to conduct long-term transmission planning for the west. The 10-year study is available at: https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition.

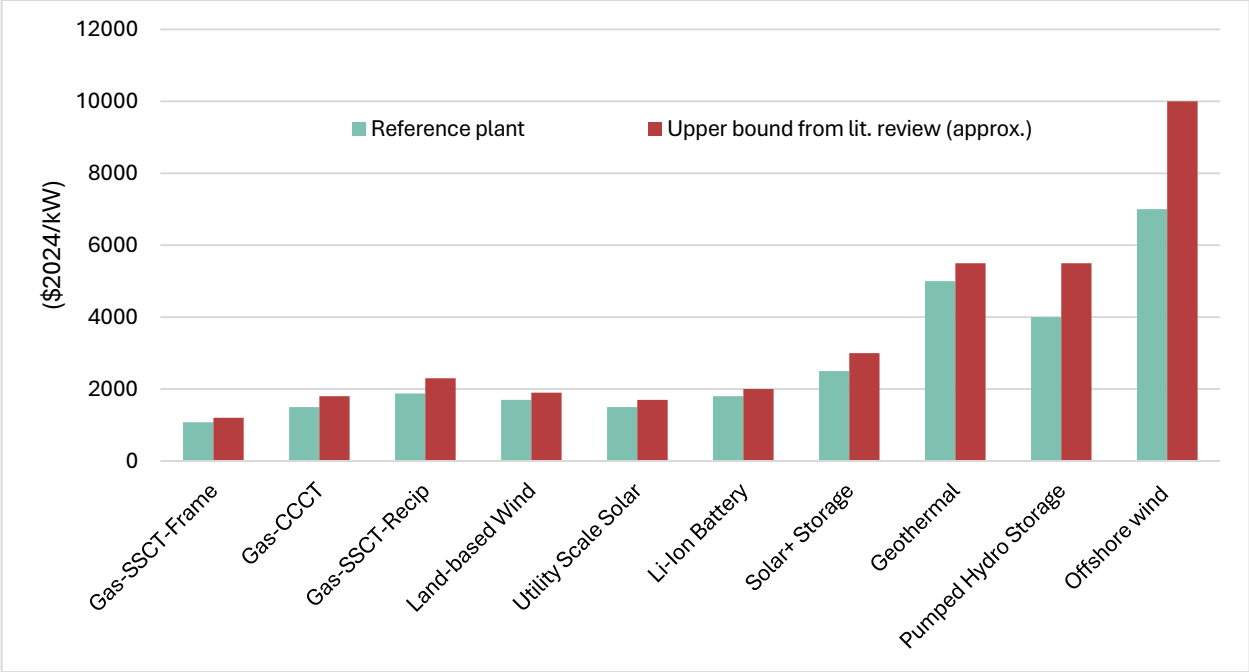
demand for new resources, and the resulting concern that these supply chain challenges would persist in the years to come. The Council also recognizes the concerns around resource development, including permitting challenges and interconnection queue timelines. Taken together, there was interest in exploring the risk of resource acquisition being more limited than initially assumed, and the cost for those new generating resources being higher due to these constraints. The Council also recognized the concerns around the pace of future transmission development and the potential that new emerging technologies might not be available on the anticipated timelines. These limitations are also included in this sensitivity to provide a very conservative look at the future.

Generating Resource Availability and Costs

This sensitivity includes two types of constraints on new generating resources that are in the primary and limited availability categories.[2] The first was to assume a higher cost of these resources. This was to reflect that fact that in a constrained system, supply and demand dynamics would suggest that costs would increase as demand exceeds supply. To develop these higher cost assumptions, the Council leveraged the higher bound of the data from the literature review informing the initial cost estimates. This resulted in a roughly 10 to 20 percent increase in cost for most resources, with some being closer to a 40 percent increase. Figure N - 2 shows the initial cost assumptions developed for each generating resource reference plant, as well as the upper bound cost from the literature review. The Council used these upper bound costs for this specific sensitivity.

[2] For more information on the classification of new generating resources and the core assumptions assumed in the Ninth Plan, see Technical Appendix G – New Generating Resources.

Figure N - 2: New Generating Resource Cost Assumptions



In addition to an increase in costs, the Council assumed the amount of new generating resources would be limited in the near-term, 2027 through 2032. Table N - 2 shows the total annual build limit assumptions for the Constrained Resources and Transmission sensitivity, relative to the reference build limit assumed across the other sensitivities. This limit essentially cuts the assumed allowable buildout in half for most of the years.

Table N - 2: Annual Build Limit Assumptions

Build Limit (MW)	2028	2030	2032
Build Limit in Constrained Resources and Transmission Sensitivity	2,600	6,900	12,100
Reference Build Limit Assumptions	6,900	13,800	23,000

Emerging Technology Delays

Between the clean policies and goals throughout the region and the anticipated new load growth, there is interest in the development of new, clean, emerging technologies that will provide important value to the system. There is also recognition that the future of these emerging technologies is highly uncertain. Recognizing this uncertainty, commenters on the Council's Issue Paper on the Preparation for the Ninth Plan asked the Council to be conservative in the assumptions around readiness of new emerging technologies.[3] Based in part on these comments, this sensitivity includes additional

[3] The Council released this issue paper in March 2024. The issue paper and a summary of comments are available on the Council's website at: https://www.nwcouncil.org/reports/2024-1.

assumptions around the delayed timelines for emerging technologies. Specifically, the Council assumed a 10-year delay in the availability of these resources.

For generating resources, this essentially pushes the timing of two of the three technologies outside of the study timeframe.[4] Only the clean long-duration storage proxy plant remains. For conservation, the Council removed the emerging technology from the supply curve entirely. This results in a sensitivity with very limited new emerging technologies available to help meet adequacy.

Table N - 3: Emerging Technology Availability Assumptions

Resource	Reference Assumption	Sensitivity Assumption
Clean Long Duration Storage	2030 selection, 2032 online date	2040 selection, 2042 online date
Clean Baseload	2035 selection, 2040 online date	Not available
Clean Peaker/Medium Duration Storage	2038 selection, 2040 online date	Not available
Conservation	Available starting 2032	Not available

Transmission

Another risk to future resource adequacy is the availability of new transmission to support bringing resources to load. Consistent with the rest of this sensitivity, the Council assumed a constrained transmission buildout by assuming only the existing transmission system (including projects under construction) was available for the entire planning period.

Changing Transmission Availability

Transmission is an important asset to the power system. This is particularly true in a system that relies more heavily on renewable resources. Renewable resources provide clean energy for the system. At the same time, due to the nature of the resource, they are often located far away from the urban load centers. Transmission is needed to deliver energy from those resources to those load centers. As loads grow and more resources are needed to meet load growth, more transmission may be needed to support the addition of those new resources.

Building on the concerns around future transmission availability, the Council developed a suite of sensitivities to isolate the impacts of varying amounts of future transmission development. The goal of these studies was to inform how resource decisions change as the transmission system changes.

[4] For simplification of OptGen modeling in the Ninth Power Plan, OptGen modeling, the online date in Table N-3 was the first date available for the model to select a resource.

The Council developed three different sensitivities with different transmission buildouts. This is intended to provide insights into what resource solutions are robust across a range of transmission buildouts and might mitigate the risk of an uncertain transmission future.

The Ninth Plan tests three different transmission buildouts in this sensitivity. One assumes the existing transmission system. This includes all the existing transmission in the ground, as well as projects that are currently under construction. The other two sensitivities are transmission plus and transmission max (see Table N - 4). The additional projects assumed in transmission plus are planned projects estimated to come online during the Action Plan period (2027-2032) with some additional transmission also on the east side of the region. The transmission max sensitivity includes additional planned projects anticipated after 2033.

Table N - 4: Transmission Sensitivities

Project	Description	Date	Sensitivity	
			Plus	Max
Cross Cascades North	650 MW across the Cascades in Washington	2031	X	X
Cross Cascades South	1,500 MW across the Cascades in Oregon	2031	X	X
Path 8 Upgrade 1	600 MW upgrade between Montana and Oregon	2035	X	X
Gateway West Segment D3	1,000 MW between Wyoming and Idaho	2035		X
Gateway West Segment E	2,000 MW upgrade across Idaho	2036		X
Path 8 Upgrade 2	Added 200 MW west to east and 1,500 MW east to west on Path 8	2036		X
Path 14 Upgrade 2	650 MW west to east and 1,000 MW east to west between Idaho and Oregon	2036		X
North Plains Connector	1,000 MW interconnection into the Dakotas	2033		X

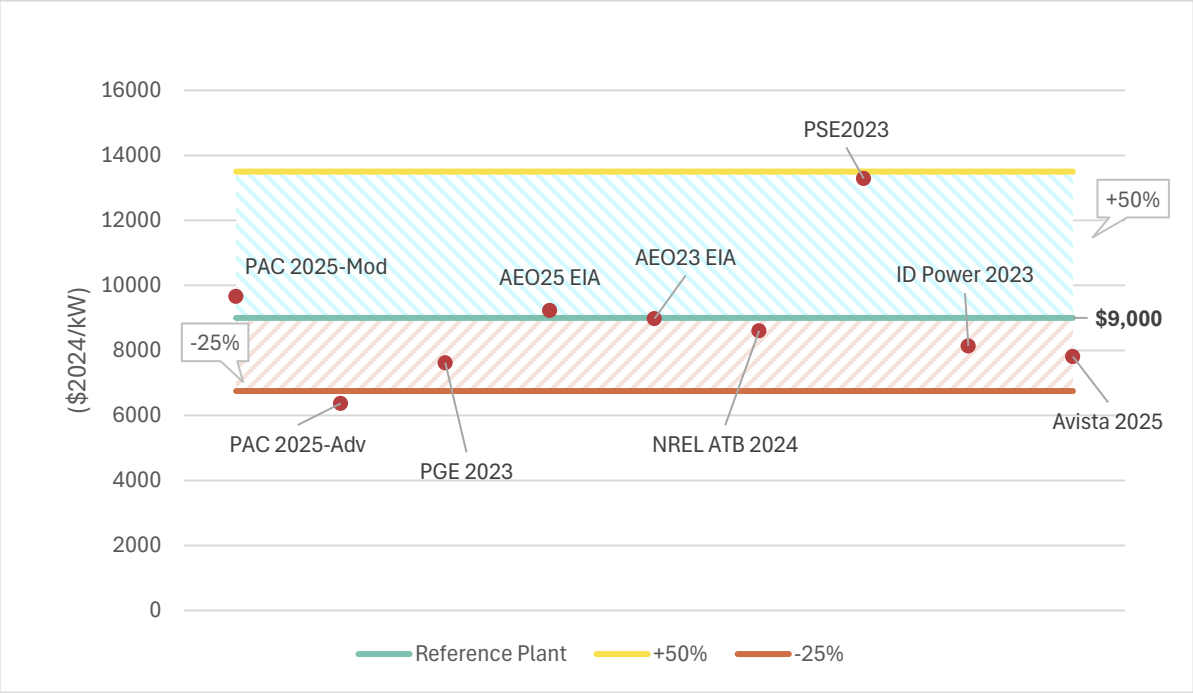
Changing Emerging Technology Costs

The future cost of emerging technologies is more uncertain than that of other resources. These technologies are either still in development or at very early stages of pilots and case studies. When these technologies become commercially viable, it is possible that the actual costs will be significantly lower or higher than those assumed in this study. The Council included this sensitivity to explore how resource decisions change with different assumed costs for these emerging technologies. Specifically, is there a price point at which any of the technologies become a more viable solution for meeting future resource needs; and is there a price point at which a technology would no longer be a part of the cost-effective strategy once it became available and reliable?

The Ninth Plan includes two sensitivities to explore the impact of changing emerging technology costs. One tested lower costs for these technologies, the other tested higher costs. To define the specific change in costs, the Council looked at cost estimates included in the literature review of the emerging technologies the reference proxy plants were based on. The Council used information from

its literature review of small modular reactors, because it was the resource with the most data available (see Figure N - 3). This showed a range of costs roughly 25 percent lower than the assumed reference plant cost to 50 percent higher. The Council decided this range was an appropriate one to use for all emerging technologies, including the assumed emerging conservation technologies. The thought was that a new resource in the market is unlikely to have a cost much lower than expected today (at least not initially). On the other hand, as these technologies develop and prove out, there is risk that the costs might be significantly higher (again, at least initially). This frame also provided a more conservative set of assumptions from which to plan and explore this uncertainty.

Figure N - 3: Cost Range for Small Modular Reactors from Literature Review



Limited Short-Duration Storage Availability

With the increase of variable energy resources on the system, there is significant interest in adding battery storage. This interest across the region, and more broadly in power systems across the globe, has the potential to create supply chain challenges that limit the availability of this resource in the near-term. To explore the implications of this risk, the Council included a sensitivity that limited the availability of short-duration, lithium-ion batteries in the Action Plan period (2027-2032). Table N - 5 provides the assumed annual limit for battery storage in this sensitivity. After the Action Plan period, the limits go away, and the model can select as many batteries as makes sense based on system needs and transmission constraints.

Table N - 5: Assumed Annual Battery Build Limit in Sensitivity

Annual Limit (MW)	2028	2030	2032
Annual Battery Build Limit	3,000	3,500	4,350

Slower Demand Side Availability

The Council's recent power plans have explored the implications of changing availability in demand side resources by including sensitivities that both increase the availability (e.g. assuming more conservation is available in the near term) and delay the availability. For the Ninth Plan, the Council updated its approach to modeling demand side potential. Specifically, the Council assumed in the initial ramp rates that the availability of new demand side resources was subject to physical constraints (e.g. contractor availability, product availability, etc.) and not subject to budgetary considerations. With this update, the Council was less concerned with the implications of the resource being developed more quickly, but still very much interested in understanding the risks of limited availability in the near-term. To answer that second question, the Council included this sensitivity that limited the availability of demand side resources by selecting slower ramp rates for all the demand side resources. Technical Appendices H, I, and J provide more information on the conservation, demand response, and rooftop solar potential, respectively. This includes a discussion of the ramp rates used generally across the supply curves and how those are limited in this specific sensitivity.

Evolving Federal Policy Landscape

Over a 20-year planning horizon, there are always elements of policy uncertainty. The Ninth Plan was developed during a period of significant change in policy at the federal level. There was a substantial shift in policies between the Biden and Trump Administrations impacting resource costs and other decisions. Recognizing that these shifts may continue, the Council developed a sensitivity to explore how resource decisions in the region are influenced by changes in policy at the federal level. The two key areas of federal policy change explored through this sensitivity were changing resource costs caused by changes in available tax credits for clean resources and changing emissions requirements for new natural gas plants.

During the Biden Administration, the Inflation Reduction Act extended and expanded tax credits for clean generating resources, making tax credits technology neutral and allowing developers to choose between the investment or production tax credits for their project. Resources taking the investment tax credit could receive up to 70 percent back for every dollar spent on the development of eligible resources.[5] Under the production tax credit, the producer could get up to 3.35 cents for every 1

[5] The base credit is 30%, with the potential for a 10% adder (up to 40%) for using domestic materials. Additionally, resources could receive an additional 30% (for up to 70%) for energy community and low-income benefit bonus.

kilowatt of production. In July 2025, the One Big Beautiful Bill Act was enacted. This policy removed tax credits for renewable resources and conservation.

The Inflation Reduction Act also implemented updates to the Clean Air Act, specifically to section 111(b) that concerns emissions standards for new stationary combustion turbines. The policy change required that base load combustion turbines with capacity factors above 40 percent implement 90 percent carbon capture and storage by 2032. In essence, this policy targeted combined cycle combustion turbines, as simple cycle combustion turbines generally operate at lower capacity factors. The rollback of the Inflation Reduction Act under the Trump Administration reverted this requirement to the best system of emissions reduction.

The Ninth Power Plan analysis assumes all policies in place at the time of modeling. For the bulk of the modeling in the plan, this was the Trump Era policies described above. Recognizing the potential for policies to reverse in some future year, the Evolving Federal Policy Landscape sensitivity tested what happens if policies like those passed during the Biden Administration resume. This includes assuming tax credits and emissions requirements for new natural gas resources return in 2030.

For the tax credits, based on advice from the Council's Generating Resource Advisory Committee, the Council assumed that new resources would select the investment tax credit more often to avoid risk of policy changes. Specifically, the Council assumed that clean resources would receive the 30 percent base credit. The Council did not include the energy community and low-income bonus, as those were less universal and more site specific. On the demand side, the Council also included tax credits for rooftop solar and conservation consistent with the Inflation Reduction Act. For new combined cycle combustion turbine natural gas plants, the Council limited the capacity of these reference plants to below 40 percent after 2030. [6,7]

It should be noted that these policies changed after Power Plan work was already underway. Due to the timing of modeling, all sensitivities in the Changing Hydro Operations scenario (discussed below) assumed the tax credits and emissions requirements for new gas resources were in place for the entire planning horizon. In addition to providing insight on the resource decisions under different hydro conditions, these sensitivities will add to the information around how federal policy impacts resource decisions in the region and more generally, what would happen if renewable generation is relatively less expensive compared to other resources.

Changing Hydro Operations

Heading into the development of the Ninth Plan, the Council anticipated the need for analysis to explore the intersection between hydropower operations and new resource development. The

[6] This limitation was modeled explicitly in the AURORA modeling for the west-wide capital expansion. This was not modeled explicitly in OptGen although in practice new combined cycle turbines tended to dispatch to low capacity factors in this sensitivity.

[7] Technical Appendices G through J provide more detail on the assumptions for new generating and demand side resources. This includes the specific treatment of tax credits or emissions requirements for this sensitivity.

Council's 2021 Power Plan identified a new tension with hydropower operations around the daily flexibility of the system. The Council's Columbia River Basin Fish and Wildlife Program has long included measures seeking to reduce the daily flow fluctuations of the system to benefit the migration of juvenile fish. At the same time, the Council's power planning analysis has shown value in ramping the system on a daily basis to support power system needs and the integration of new renewable resources in the region. Given this tension, the Council planned a scenario to explore these trade-offs in flexibility.

Adding to this, the Ninth Plan was developed at a time of particularly high uncertainty around future hydropower operations, particularly those operations designed to protect and mitigate for the impacts on fish and wildlife. The Council was in the process of developing the 2026 Columbia River Basin Fish and Wildlife Program, which was grappling with incorporating recommendations and comments on the recommendations into the amendment process, including recommendations for different hydro system operations. At the same time, in June of 2025, President Trump issued a Presidential Memorandum withdrawing from the 2023 Resilient Columbia Basin Agreement, which, among other things, had established a set of operations for fish that was expected to hold for ten years.[8] Withdrawing from the agreement created uncertainty not just for long-term operations, but for the near-term 2026 operations as well.

In August 2025, the Council scoped out four sensitivities to include in this scenario. The purpose was to reflect the uncertainty around future operations, while also providing insights to inform the ongoing Fish and Wildlife Program amendment process. Table N - 6 outlines the sensitivities explored in this scenario and the sections below provide more detail on the specific assumptions changed for each sensitivity.

Table N - 6: Changing Hydro Operations Scenario Scope

Sensitivity	Description
2020 BiOp Flex Spill Operation	Assumes the operations based on the 2020 Columbia River System Operations Environmental Impact Statement. This sensitivity was intended to provide one end of the bounds for potential 2026 operations, based on the assumption that legally, until another agreement was in place, the system should revert to these operations.
2023 RCBA Operations	Assumes the operations as defined in the 2023 Resilient Columbia Basin Agreement. This sensitivity was intended to provide an alternative set of operations with a focus on steady spill throughout the spring, acting as a potential bookend to the range of uncertainty around 2026 operations.

[8] In December 2023, the U.S. Government released a set of commitments in partnership with the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington. These commitments included a range of actions related to fish and wildlife and power planning, that ultimately resulted in a 10-year stay in the long-standing National Wildlife Federation et al v. National Marine Fisheries et al litigation.

Sensitivity	Description
Recommended Spill and MOP Targets	Analyzed specific minimum operating pool elevations and limits, and spill operations, as recommended by some of the states and tribes in the Fish and Wildlife Program amendment process. This sensitivity was intended to provide insights on potential hydropower system impacts of those specific recommendations.
Limited Flex Operation	Analyzed limitations of the hydro system's ability to change daily elevations and outflows at the lower Columbia and lower Snake River projects. This was intended to inform on the hydropower system implications of limiting the daily flexibility of the system.

The bulk of the hydropower system operations are consistent across these four sensitivities. This includes requirements for hydropower, flood control, fish passage and protection, irrigation, recreation, navigation, municipal and industrial use, wildlife habitat, cultural resources, and water quality and temperature. The Council uses data from the Council's Fish and Wildlife Program, biological opinions, the Water Management Plan, the Fish Operations Plan, the Columbia River Treaty, and other such documents to define these operations. The changes focus on the minimum elevations and targets, spring and summer spill for juvenile fish passage, outflow ramps of projects, and reserve allocations.

More information on the hydro generation set up and assumptions is included in Technical Appendix M – Needs Assessment Results.

2020 BiOp Flex Spill Operation

This sensitivity was intended to provide a potential bookend to reflect "current" operations. By current, the focus was operations currently planned for 2026 and beyond, assuming they held over the planning horizon. The Council selected the 2020 Columbia River System Operations Environmental Impact Statement to represent the current operations, under the assumption that with the withdrawal from the 2023 Resilient Columbia Basin Agreement, operations would revert to this Biological Opinion (BiOp). The specific element of these operations that is different from other sensitivities is the assumed spring and summer spill levels and dates. Table N - 7 outlines the specifics of those spill operations. As seen in Table N - 7, the spring spill operations at most of the lower Snake River and lower Columbia River projects assumed a flex spill approach, spilling to 125 percent total dissolved gas for 16 hours of the day and then lower spill levels for the other 8 hours. This operation was designed to balance periods of spill for juvenile migration with periods of reduced spill and more power generation during key hours.

Table N - 7: 2020 BiOp Spill Operations[9]

Project	Spring Operation Lower Snake: 4/3-6/20 Lower Columbia: 4/10-6/15	Summer Operation Lower Snake: 6/21-8/14 Lower Columbia: 6/16-8/14	Summer Operation 8/15-8/31
Lower Granite	16 hour: 125% TDG 8 hour: 20 kcsf	18 kcsf	RSW or 7 kcsf
Little Goose	16 hour: 125% TDG 8 hour: 30%	30%	ASW or 7 kcsf
Lower Monumental	16 hour 125% TDG 8 hour: 30 kcsf	17 kcsf	RSW or 7 kcsf
Ice Harbor	16 hour: 125% TDG 8 hour: 30%	30%	RSW or 8.5 kcsf
McNary	16 hour: 125% TDG 8 hour: 48%	57%	20 kcsf
John Day	16 hour: 125% TDG 8 hour: 32%	35%	20 kcsf
The Dalles	24 hour: 40%	40%	30%
Bonneville	16 hour: 125% TDG 8 hour: 100 kcsf	95 kcsf	50 kcsf

2023 RCBA Operations

The Council included a second sensitivity assuming spill operations from the 2023 Resilient Columbia Basin Agreement. The spill operations under the Resilient Columbia Basin Agreement provide steady spill at the lower Snake and lower Columbia River projects. In other words, rather than deploying the flex spill operations in the spring as defined in the 2020 BiOp, this agreement established a 24 hour spill up to 125 percent total dissolved gas for most of the lower river projects. The Council chose this set of operations to represent a steady spill operation as an alternative bookend to the 2020 BiOp operations defined above. The intent was that these two sets of operations would provide a range of information that could reasonably represent possible operations for 2026.

In addition to increasing spring spill, the 2023 Resilient Columbia Basin Agreement changed the end dates for summer spill operation. These were moved forward two weeks, from mid-August to the end of July. Table N - 8 outlines the specific spill assumptions for each of the projects.

[9] Acronyms in Table N - 7 are: TDG – total dissolved gas; kcsf – thousand cubic square feet; RSW – removable spillway weir and ASW – adjustable spillway weir.

Table N - 8: 2023 Resilient Columbia Basin Agreement Spill Operations

Project	Spring Operation Lower Snake: 4/3-6/20 Lower Columbia: 4/10-6/15	Summer Operation Lower Snake: 6/21-7/31 Lower Columbia: 6/16-7/31	Summer Operation 8/1-8/31
Lower Granite	125% TDG	18 kcsf	Spillway weir flow
Little Goose	125% TDG	30%	ASW or 7 kcsf
Lower Monumental	125% TDG	17 kcsf	SW flow or 8 kcsf
Ice Harbor	125% TDG	30%	SW flow or 9 kcsf
McNary	125% TDG	57%	20 kcsf
John Day	16 hour: 40% 8 hour: 125% TDG	35%	20 kcsf
The Dalles	40%	40%	30%
Bonneville	125% TDG	95 kcsf	50 kcsf

Recommended Spill and MOP Targets

The Council began development of the Ninth Plan while it was also working on the Columbia River Basin Fish and Wildlife Program amendment process. To provide information for that process while also informing power planning, the Council developed a third sensitivity to model some of the recommendations submitted to the Council through that amendment process. Specifically, this included recommendations from some of the states and tribes on spill operations and minimum operating pool elevations and targets.

The Council received recommendations from some of the states and tribes about extending summer performance spill through August 31. The baseline spill operations assumed at the time of these comments were those defined in the 2023 Resilient Columbia Basin Agreement, in Table N - 8 above. This recommendation essentially would change the end date for summer performance spill from the July 31 date in the agreement to August 31.

Additionally, the Council received recommendations from some of the states and tribes around changes to minimum operating pool elevations and targets for the lower Snake and lower Columbia projects. These were part of a suite of recommendations seeking to reduce water travel time to support juvenile migration. The lower Snake River projects currently operate at minimum operating pool elevations with a 1.5-foot hard constraint and 1.0-foot soft constraint from April 3 to August 14. The recommendations were to tighten these elevations to a 1.0-foot hard constraint and a 0.5-foot soft constraint, and also to extend the period to March 1 to September 30. The lower Columbia River projects do not currently have minimum operating pool target elevations for the spill season. The joint entities recommended that operations at these projects be kept within 1.5 foot of minimum operating pool hard constraint and 1.0-foot soft constraint for this same period of March 1 to September 30.

This sensitivity models both the spill and minimum operating pool elevation targets. The specific minimum operating pool targets modeled in this sensitivity are in Table N - 9.

Table N - 9: Minimum Operating Pool Elevations

Project	Current Pool Elevation Operations (feet)	Recommended Operations Modeled in Sensitivity (feet)
Lower Granite	773-734.5	773-734
Little Goose	633-634.5	633-634
Lower Monumental	537-538.5	537-538
Ice Harbor	437-438.5	437-438
McNary	337-340	337-338.5
John Day	262-266.5	262.5-264
The Dalles	157-160	157-158.5
Bonneville	71.5-76.5	71.5-73

Limited Flex Operation

The final sensitivity included in this scenario focuses on the question of power system implications from reduced daily flexibility of the hydropower system. As discussed above, the ability to ramp the hydropower system on a daily basis to meet power system needs can provide value for integrating new renewable resources into the system. At the same time, the Council's Fish and Wildlife Program has called on the region to minimize daily fluctuations for the benefit of fish. This sensitivity aims to provide more insight on the power system implications of this balance.

The Council's GENESYS model sees more operational flexibility than is currently being utilized in the system today. To guide this sensitivity, the model was limited to represent operations more akin to current system dynamics. Specifically, the daily outflow range for each project was limited to align more closely with 2020-2024 actual operations. Additionally, the Council reduced the reserve requirements on the lower projects.[10]

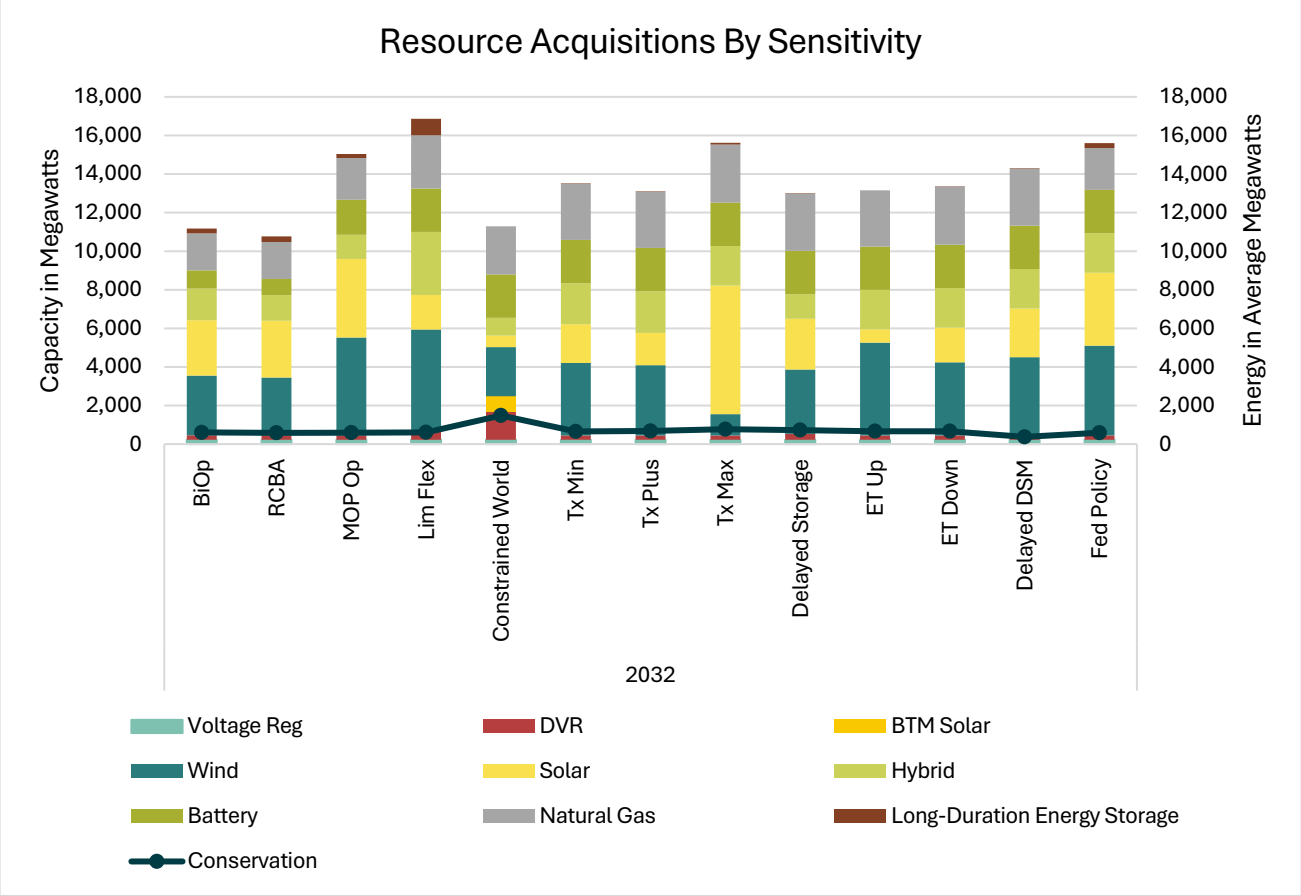
[10] See Technical Appendix M – Needs Assessment Results for more information on the assumed outflows.

Modeling Results

This section walks through the results of the regional resource optimization modeling, conducted in OptGen/SDDP. This builds on the work from the Council's needs assessment and west-wide market availability studies.[11]

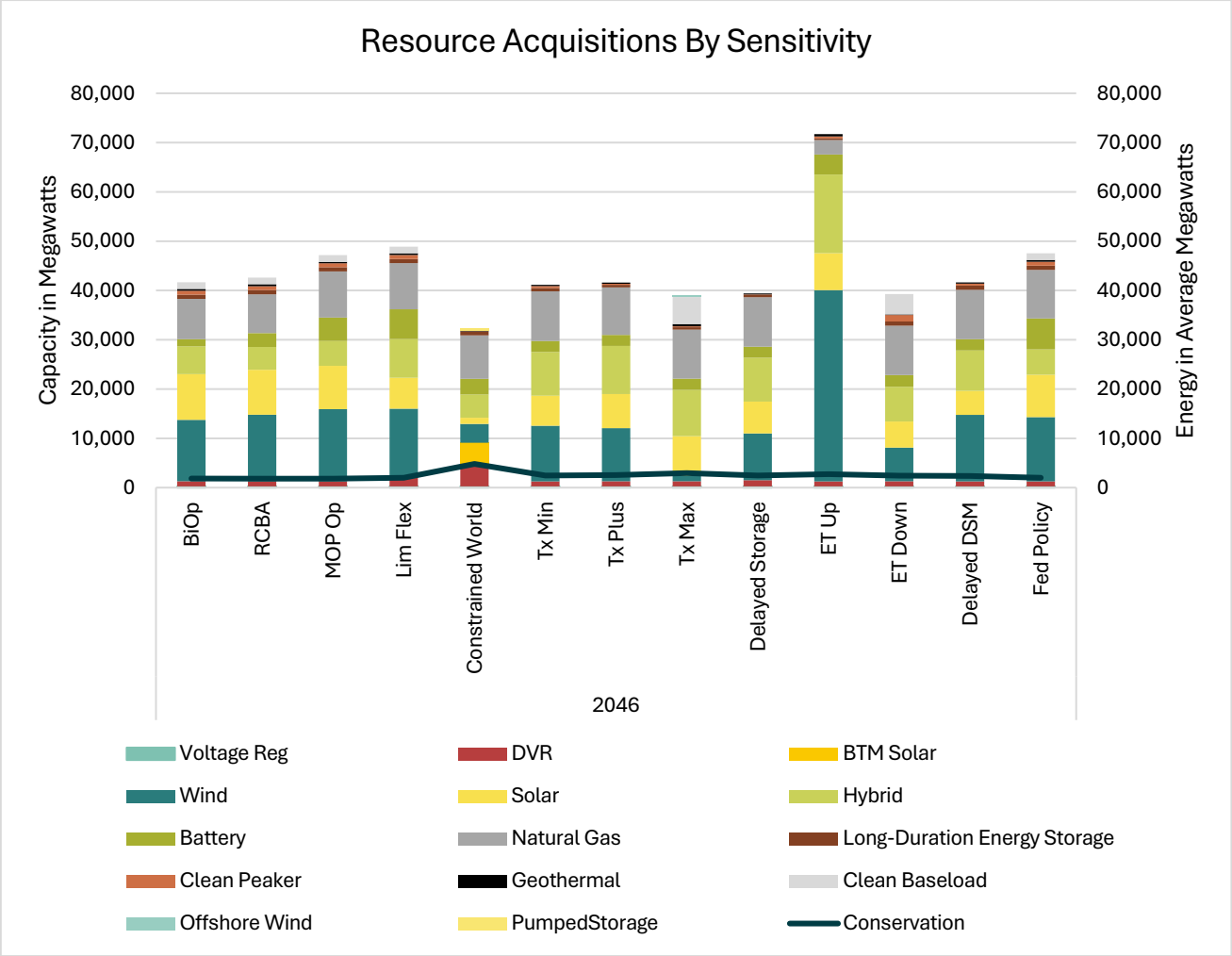
The modeling showed a suite of resources being selected across every sensitivity. In the Action Plan period (2027-2032) this includes: conservation, demand response, voltage regulation, renewables, storage, and natural gas as can be seen in Figure N - 4. In the broader study (through 2046), geothermal, long-duration energy storage, and medium duration energy storage were selected in all sensitivities for which the resource was available as can be seen in Figure N - 5. The clean baseload emerging technology was selected in roughly 60% of the sensitivities. Only three resources were not selected in a robust fashion across the modeling: offshore wind, pumped storage, and rooftop solar.

Figure N - 4: Resource Acquisition by Sensitivity in 2032



[11] See Technical Appendix L – Wholesale Market Availability Results and Technical Appendix M – Needs Assessment Results for more information on these studies.

Figure N - 5: Resource Acquisitions by Sensitivity in 2046



Primary Resource Themes

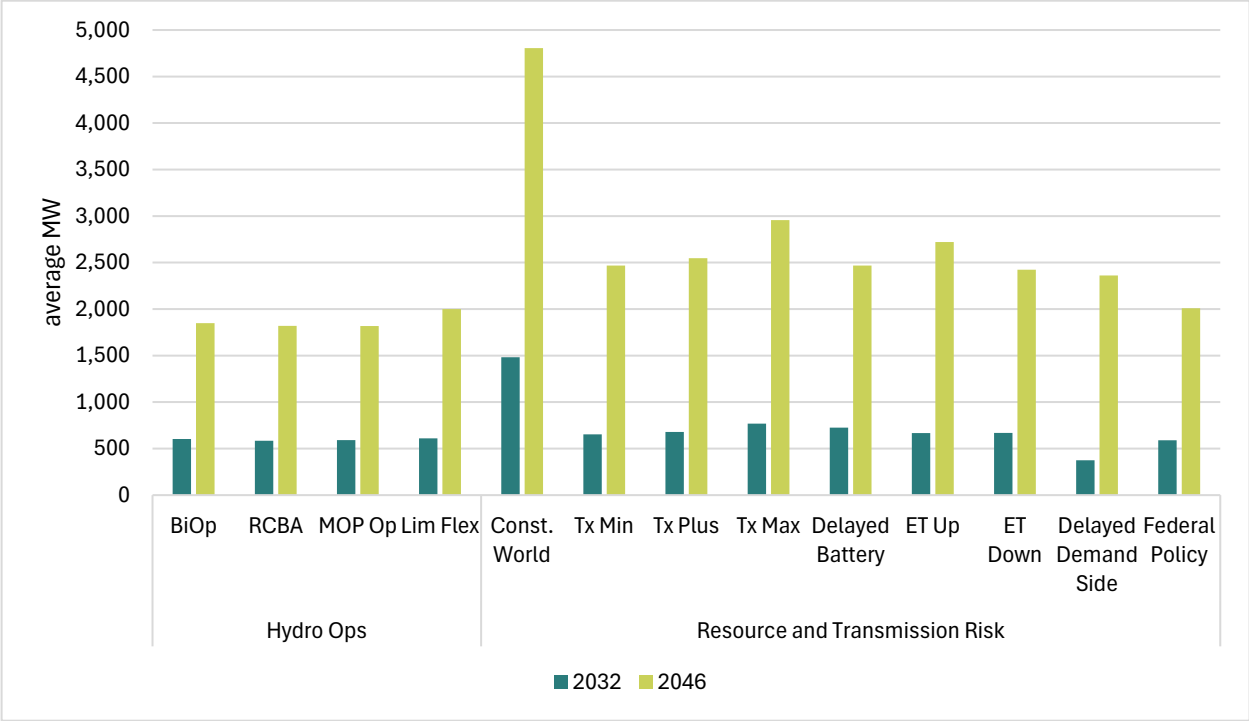
This section focuses on the results for those resources considered to be commercially available today that were selected in all sensitivities.

Conservation

Conservation was acquired in every sensitivity to provide energy, reduce loads and thereby lower the planning reserve margin requirements, and meet clean policies and goals. The amount of conservation acquired in each sensitivity varied based on the assumed costs and constraints of other resources. To maintain adequacy, the model selected more conservation when supply side resources were limited and costs for those resources were higher. Less conservation was selected in sensitivities with lower price for supply side resource, particularly renewables, as those resources start to become a more cost-effective way to provide energy to the system.

Figure N - 6 provides the conservation build by 2032 and by 2046. The highest build is in the Constrained New Resource and Transmission sensitivity. In this sensitivity, the supply side is constrained to the point that to maintain resource adequacy, the model selects all available conservation. The least amount of conservation in the near-term (2032) is acquired in the Delayed Demand Side sensitivity, as there is less available to the model. The amount of conservation acquired both in the near-term and long-term is similar across the Changing Hydro Operations sensitivities and the Changing Federal Policy sensitivity. These are the sensitivities that assume federal tax credits for renewables, akin to Biden Administration-era policies. The result is that renewables become more cost-competitive and are therefore more readily acquired by the model, offsetting the need for conservation.

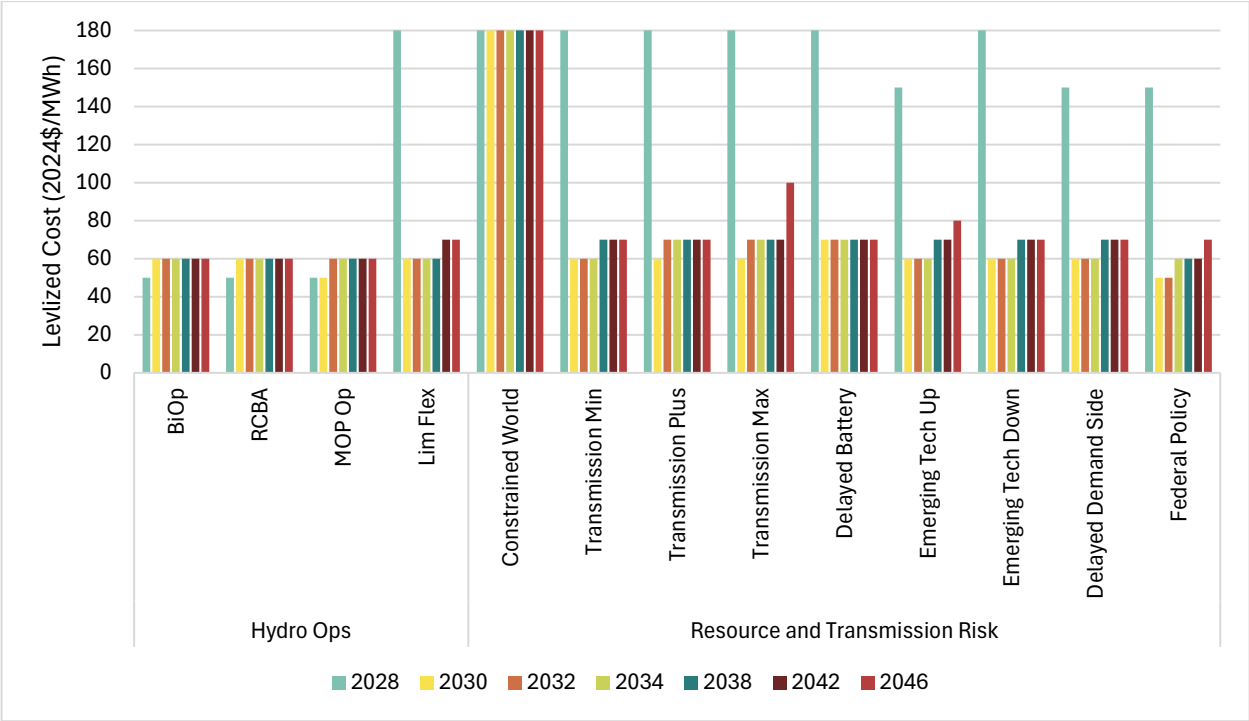
Figure N - 6: Conservation Build by 2032 and 2046



Another finding in the conservation results was that generally the model wanted to acquire conservation higher up the cost curve as it moved through time. Figure N - 7 shows the maximum levelized cost-bin acquired in each sensitivity. A couple important notes: First, for some of the 2028 years and the Constrained New Resource and Transmission sensitivity, the figure shows costs going up to the top of the chart. In all cases, the model acquired all available conservation, including conservation over $200/MWh. This is a clear signal from the modeling that at times when the supply side is constrained, for example in 2028 with limited planned resource options and in the Constrained Resource and Transmission Risk sensitivity, the model sees value in acquiring more expensive conservation as a way to maintain adequacy. Second, generally, the model wants to go higher up the cost curve over time. This can be seen in most sensitivities where the value of conservation acquired

by the end of the study (2046) is higher than that acquired in 2030, the first year the model is less constrained on supply side resources.[12]

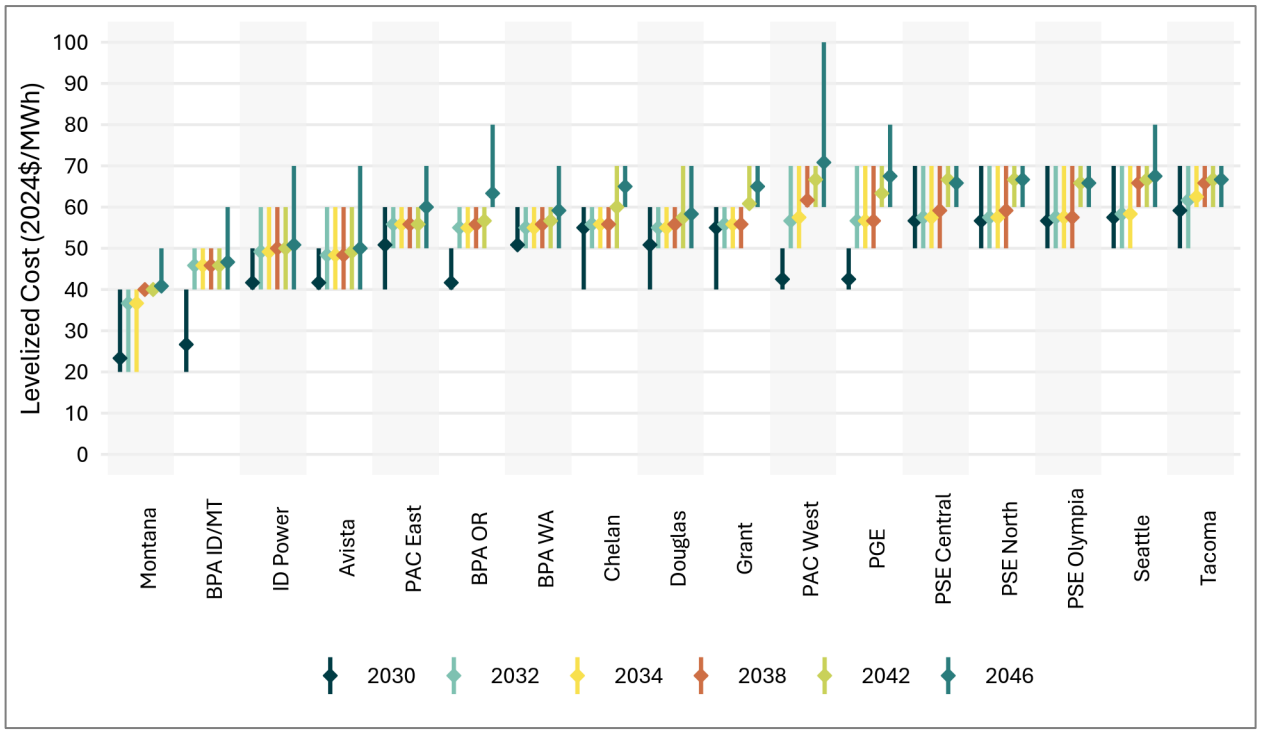
Figure N - 7: Maximum Cost Bin Acquired in Each Sensitivity



While Figure N - 7 provides the maximum levelized cost bin across the region for each sensitivity, Figure N - 8 digs deeper to show how the levelized cost changes across the region. This is a line range plot showing the range of costs acquired for each zone across the sensitivities. It excludes the Constrained Resource and Transmission Risk sensitivity and 2028, as both of those skew the overall trend due to the supply side challenges. As shown in this figure, there is a difference in the value of conservation being acquired across the modeling zones. The diamonds show the average cost for each zone across the sensitivities.

[12] In the 2028 snapshot year, the only generating resources available in the model are planned resources already identified by regional entities. The rationale is that, due to lead times for developing resources, it is unlikely other new options would be available if not already planned. By 2030, there is the potential for resources beyond those planned resources to be identified and developed, and so those constraints are lifted from the model.

Figure N - 8: Levelized Cost Bins Across Sensitivities for Each Zone



In Figure N - 8, Montana zones consistently show the lowest signal, starting off at $20/MWh and going up to $50 or $60 in the final year. The zones in the Puget Sound area, however, start off at around $50/MWh and generally get to $70 by the end of the study. When looking at the averages, a broader trend emerges. The averages for the Montana zones are on the low end of the line range, whereas the averages for the Puget Sound zones are on the top end.

These main findings of locational value, increased value over time, and increased value under periods of supply chain constraints and resource cost increases all informed the overall conservation target recommended in the regional resource strategy.

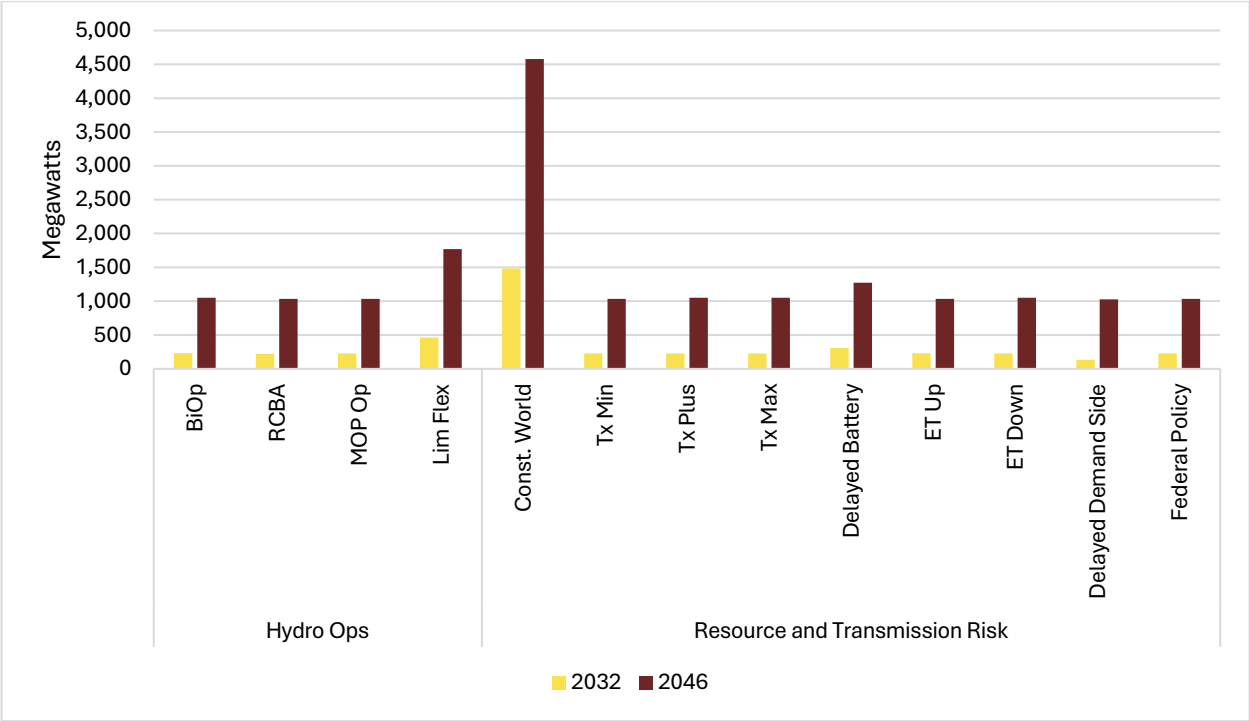
Demand Response

Demand response was selected in every sensitivity. Demand response lowers loads at certain times, which reduces the required planning reserve margin at those times. Demand response is also an emissions-free option that can support policy during the times when it reduces load.

The amount of demand response acquired in each sensitivity varied based on assumed constraints of supply side resources and costs of those resources, as well as overall system flexibility. Figure N - 9 shows the demand response build across the sensitivities for 2032 and 2046. The highest levels of demand response were acquired in the Constrained Resource and Transmission, Delayed Battery Storage, and Limited Flexibility sensitivities. In the first two of these, supply side resources, including standalone storage which competes with demand response, were limited. This resulted in a higher investment into demand response to maintain adequacy. In the Limited Flexibility sensitivity, the existing hydropower system was limited in its ability to ramp on a daily basis to provide flexibility and

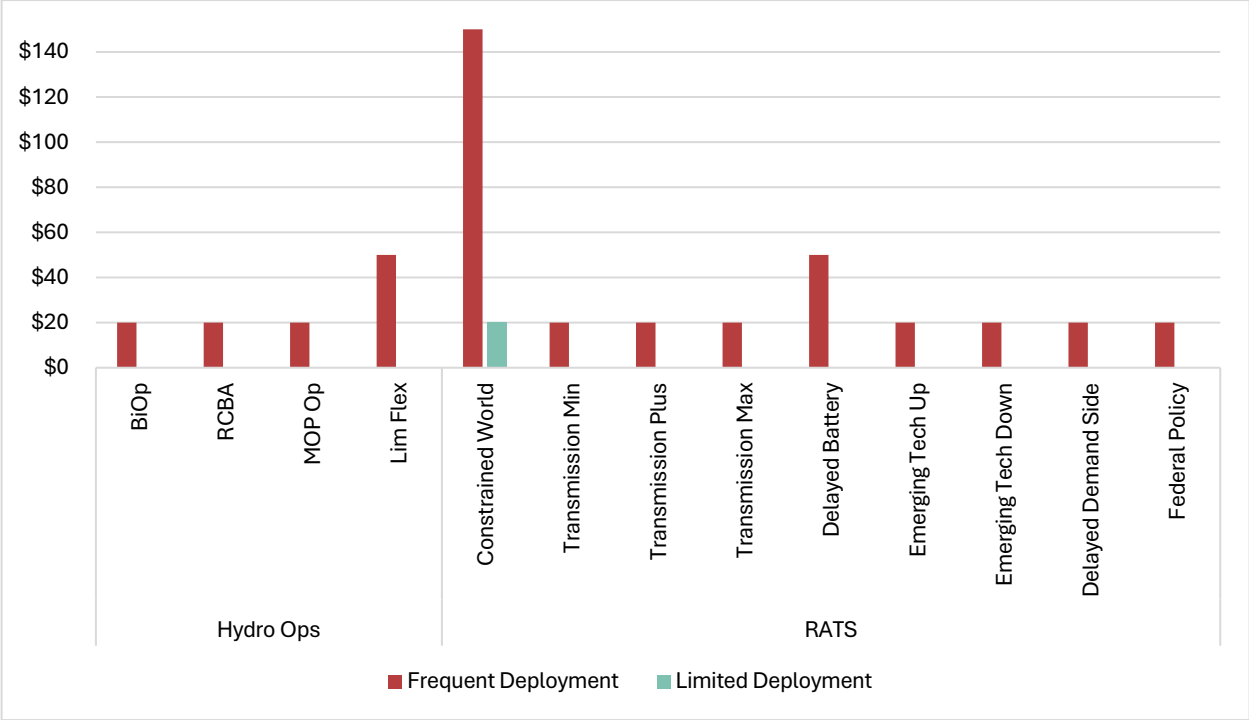
support the integration of renewables. This resulted in the model needing to acquire more new resources to provide flexibility, including demand response.

Figure N - 9: Demand Response Build in 2032 and 2046



Beyond those three sensitivities, the overall demand response build was fairly limited. Figure N - 10 shows the maximum levelized cost bin acquired for demand response by 2032 for each sensitivity. This figure breaks out the frequent deployment and limited deployment demand response. This figure shows that the model prefers the frequent deployment products, providing more regular flexibility to the system. It also shows that generally the model does not want to go higher than the lowest cost bin for demand response. Unlike conservation, which shows a signal for higher cost conservation over time, the demand response acquisition looks similar in 2046 as is shown for 2032. In other words, the model does not show value for higher cost demand response in the future to meet needs.

Figure N - 10: Maximum Demand Response Cost Bin, by Type, in 2032



One likely reason for this result is how demand response competes with other resources in the system. As discussed more below, the model acquires both natural gas and hybrid solar plus storage resources in large amounts. These resources provide energy for the system, as well as provide flexibility. They also can provide reserves. Once these resources are acquired, there is less of a role for demand response specifically to meet needs.

The Council also identified another potential challenge for the modeling of demand response in the Ninth Plan. For this plan, demand response was provided to the model as an "energy efficiency" resource. This means that once the model selected the resource, it was deployed as shaped to meet needs, regardless of the underlying future conditions. For example, the same amount of demand response was used in a future with low market prices as in a future with high market prices. This is not the reality of demand response implementation, as utilities will use price signals to guide demand response events. Second, the model uses a typical day format, which likely reflects less volatility in market prices as seen in reality. This too likely masks the signal for demand response in the model.

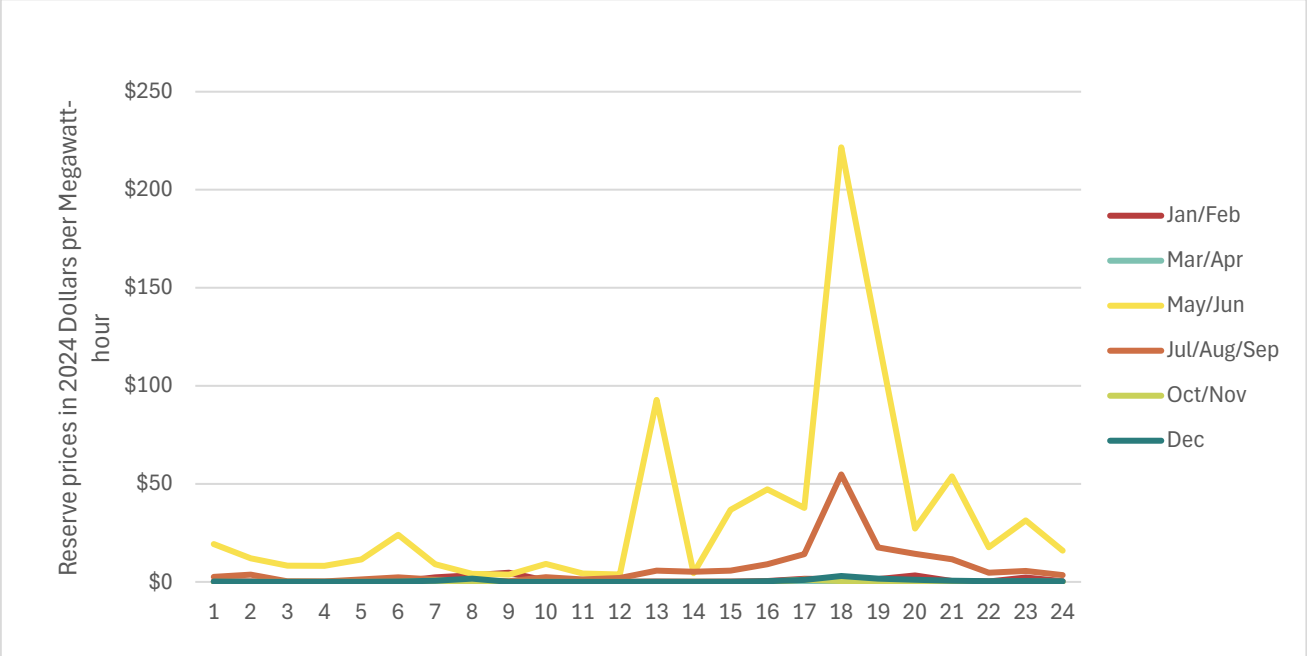
Additionally, as described above, in the typical day modeling as described in Technical Appendix K – Modeling Framework, power prices are defined for a typical day with expected demand for that season. To account for the difference between the expected demand peak and seasonal peak, additional reserves were added so the model would know to have enough resources to meet seasonal peaks. These seasonal peak reserves make up a large portion of the reserves in the model, over 75 percent of the total reserves in 2032 in all sensitivities.

The model creates reserve prices when meeting reserves is marginal, or reserve providing resources are scarce. Unfortunately, in the modeling, while demand response could lower demand in certain

hours, it was not one of these resources that could meet these seasonal peaking reserves directly. Thus, instead of using the model resource selection in this case it could be useful to see what price signal is left to mitigate.

For example, the model shows a reserve price signal that is high[13] during certain hours in the late spring and summer, per Figure N - 11. It is clear the model did not see additional other resources as advantageous to addressing those peak needs, since it could have lowered the price and selected those resources as part of the strategy. However, since demand response was not available to address this need directly, it is unclear if the model would have chosen demand response if given an opportunity.

Figure N - 11: Reserve Prices by Season in 2032



The Council did identify other results that might suggest value for a product similar to demand response. These include the curtailment of hydrogen demand in the model.

Voltage Regulation

Voltage regulation is a demand side resource that regulates the voltage on the distribution system to provide energy system. This can be operated in a couple of different ways. One approach is to lower the voltage once and keep it at that lower level. This approach is akin to conservation and is typically called conservation voltage reduction. The second approach is to lower the voltage at times when it

[13] The signal in practice is higher than this from the model results because the model in spring often bumped against the reserve requirement as a constraint. In the figure prices are capped at 1,000 dollars per megawatt hour for illustration.

provides value to the system, but keeps the voltage higher at other times for economics. This approach is called demand voltage regulation.

For the Ninth Plan, the Council modeled this resource separately from both conservation and demand response, allowing the model to determine whether there was value in this product, and if so, what strategy would best meet regional needs. This entire resource was selected in every sensitivity, driven by the near-zero to negative levelized cost of this resource. Generally, the model operated this more as conservation resource in the early years of the power plan (see Figure N - 12) and more of a demand response product in the later years (see Figure N - 13). These utilization charts show when the resource is operating. In Figure N - 12, the resource is maxing out its operations for most hours of the day across all seasons, except some minor drops in the spring period. Figure N - 13 shows more variability, however, particularly in the spring.

Figure N - 12: Voltage Regulation Utilization in 2032 for Region

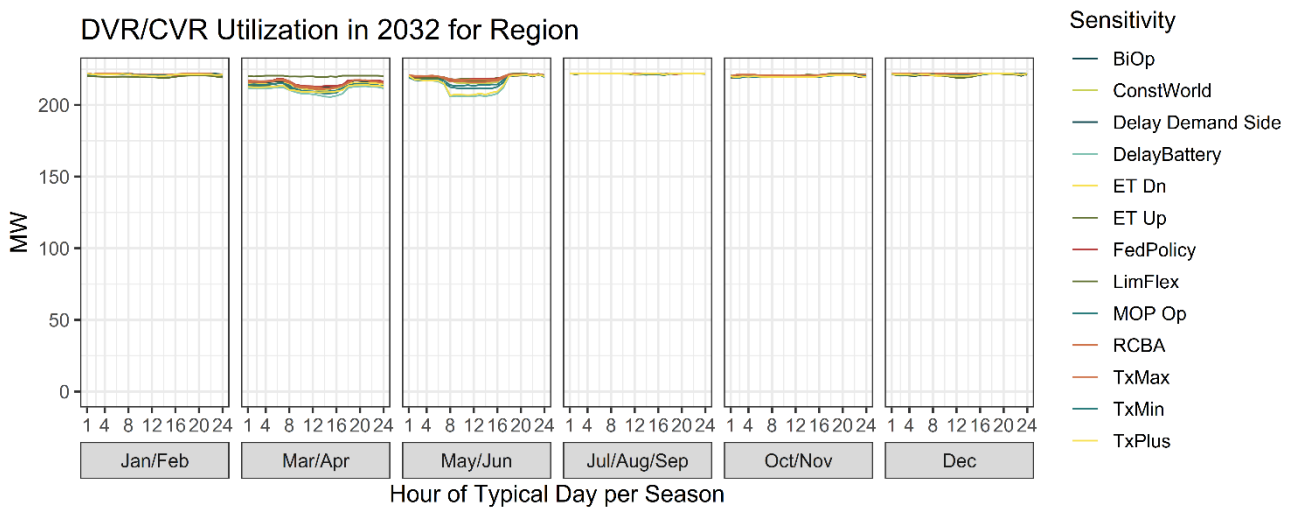
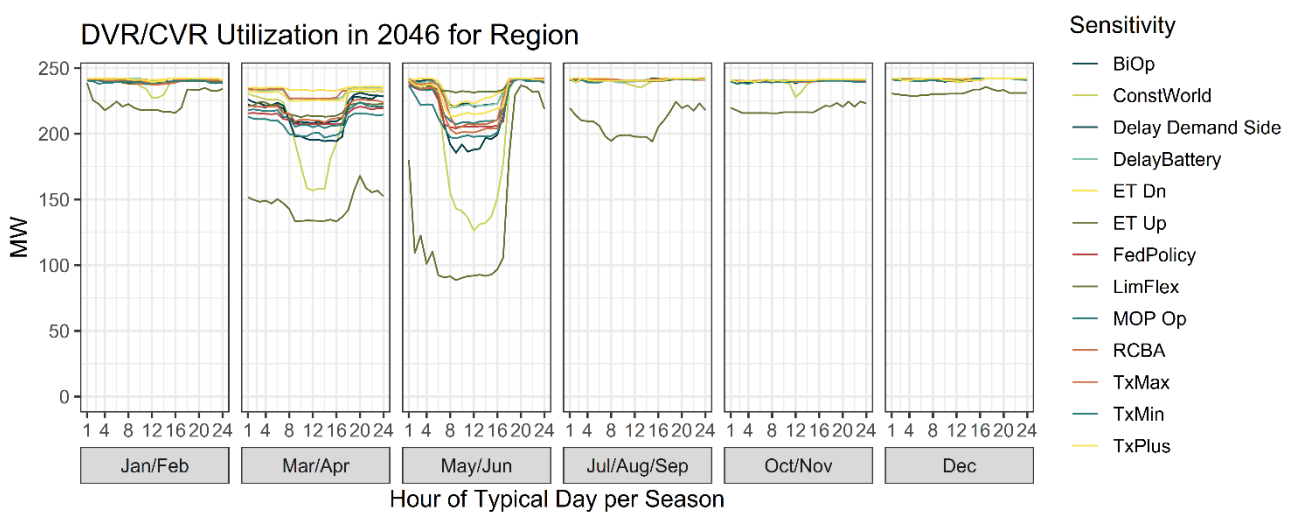


Figure N - 13: Voltage Regulation Utilization in 2046 for Region



The figures above show the regional approach to voltage regulation, but there are differences seen across the zones. Figure N - 14 through Figure N - 19 show the utilization for 2032 and 2046 in Oregon, Washington, and Idaho/Montana, respectively.

Figure N - 14: Voltage Regulation Utilization in 2032 in Orgon

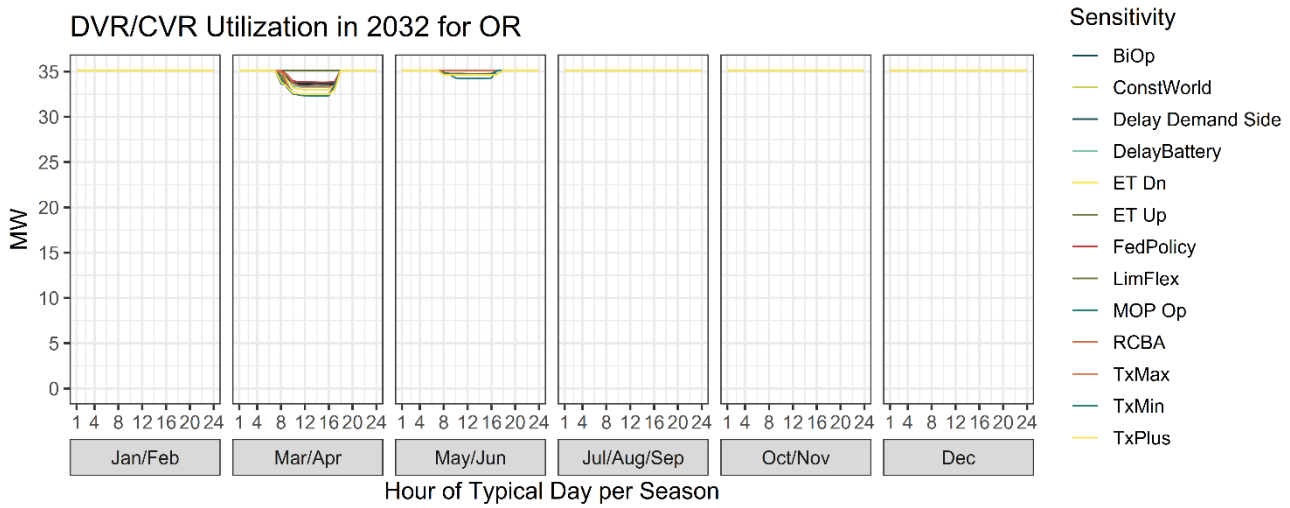


Figure N - 15: Voltage Regulation Utilization in 2046 in Oregon

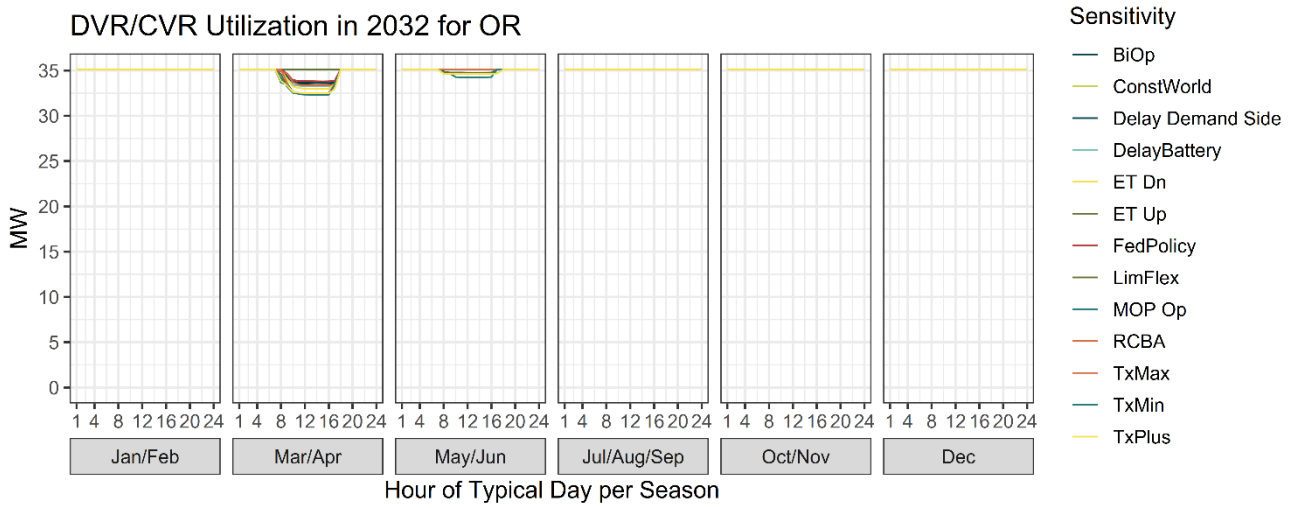


Figure N - 16: Voltage Regulation Utilization in 2032 in Washington

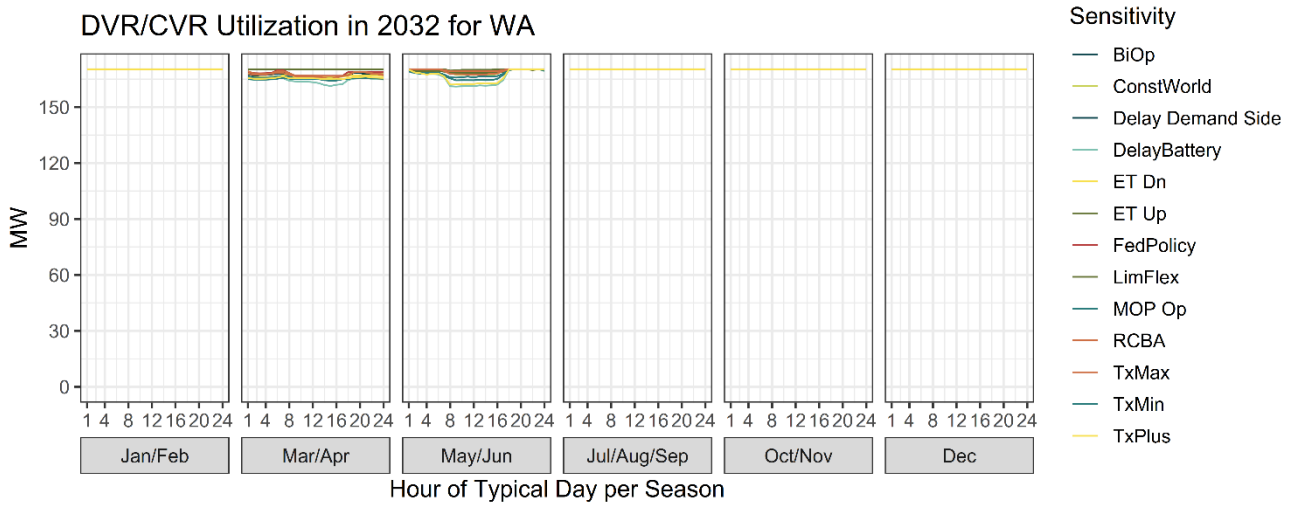


Figure N - 17: Voltage Regulation Utilization in 2046 in Washington

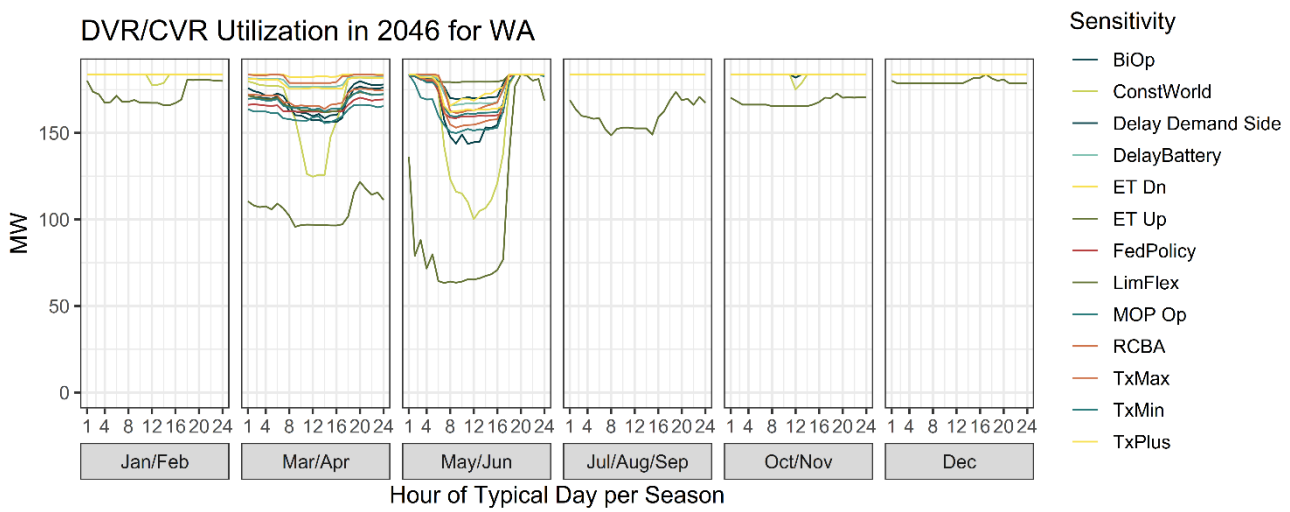


Figure N - 18: Voltage Regulation Utilization in Idaho and Montana in 2032

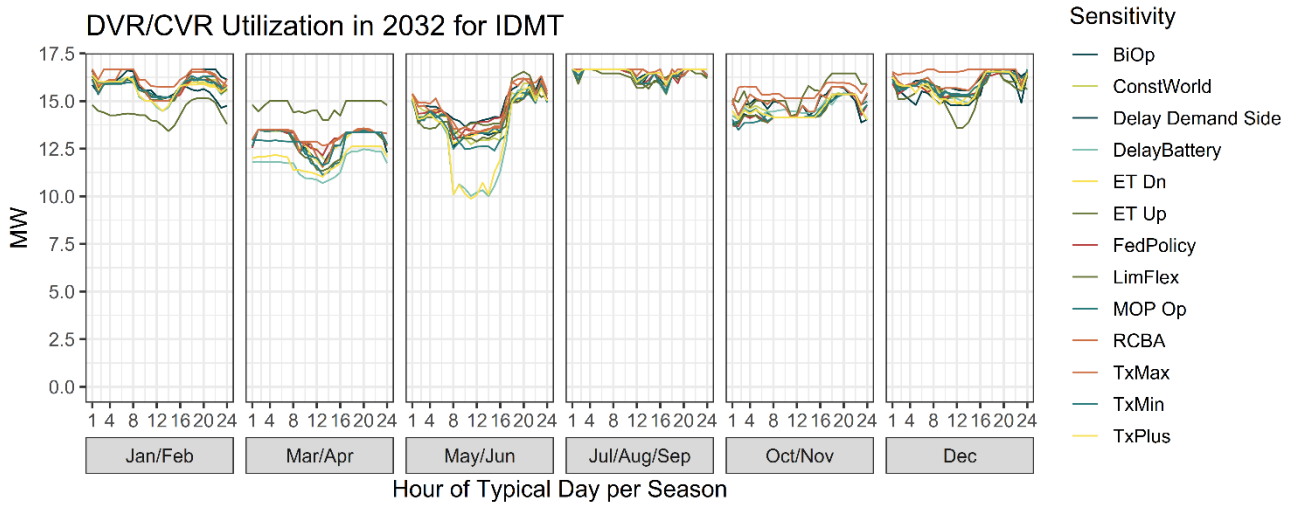
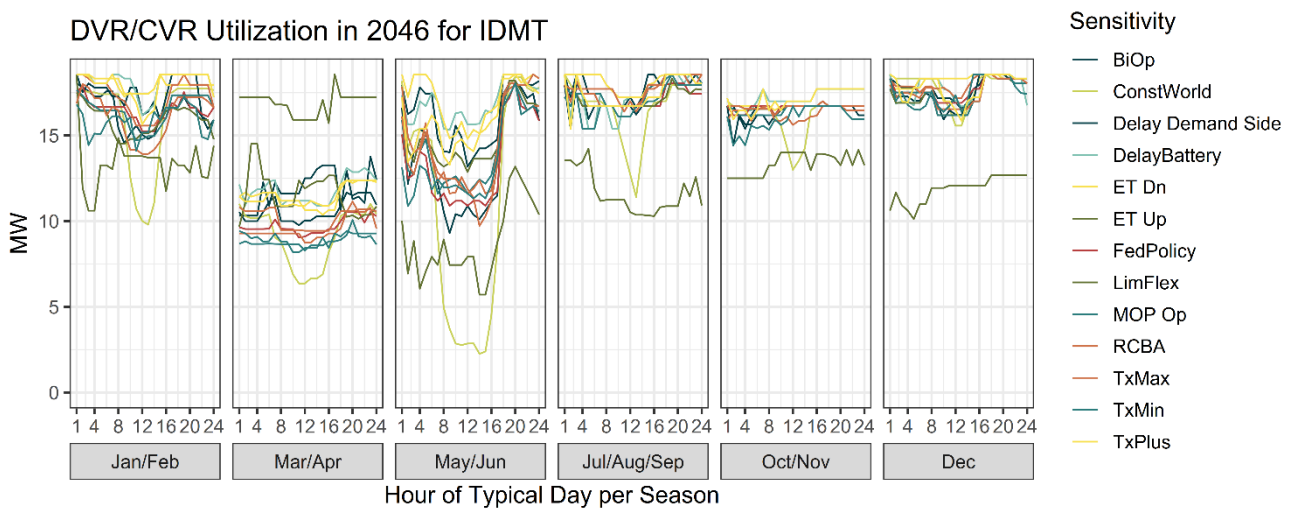


Figure N - 19: Voltage Regulation Utilization in Idaho and Montana in 2046



Renewables

This section focuses on solar and onshore wind, including solar plus storage. Conventional geothermal and offshore wind are covered in separate sections below. Solar, wind, and solar plus storage were selected in all sensitivities. These resources provide energy to the system and support the region in meeting clean policies and goals. Solar plus storage hybrid resources also support the system in meeting its planning reserve margins.

Figure N - 20 and Figure N - 21 show the renewable build across sensitivities by 2032 and 2046, respectively. One trend seen in both these figures is a general preference for a balanced approach between wind and solar. While this is not always the case, there is roughly a 50:50 split between wind and solar (including solar plus battery) resources.

Figure N - 20: Renewable Build by 2032

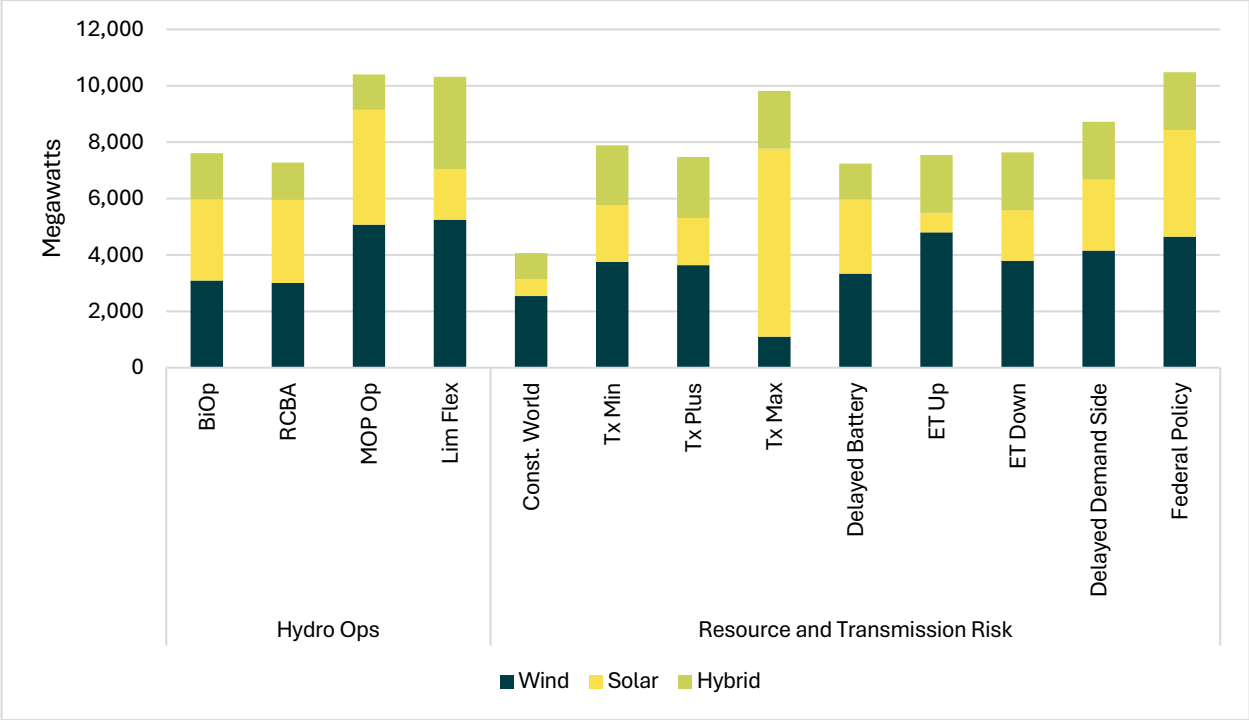
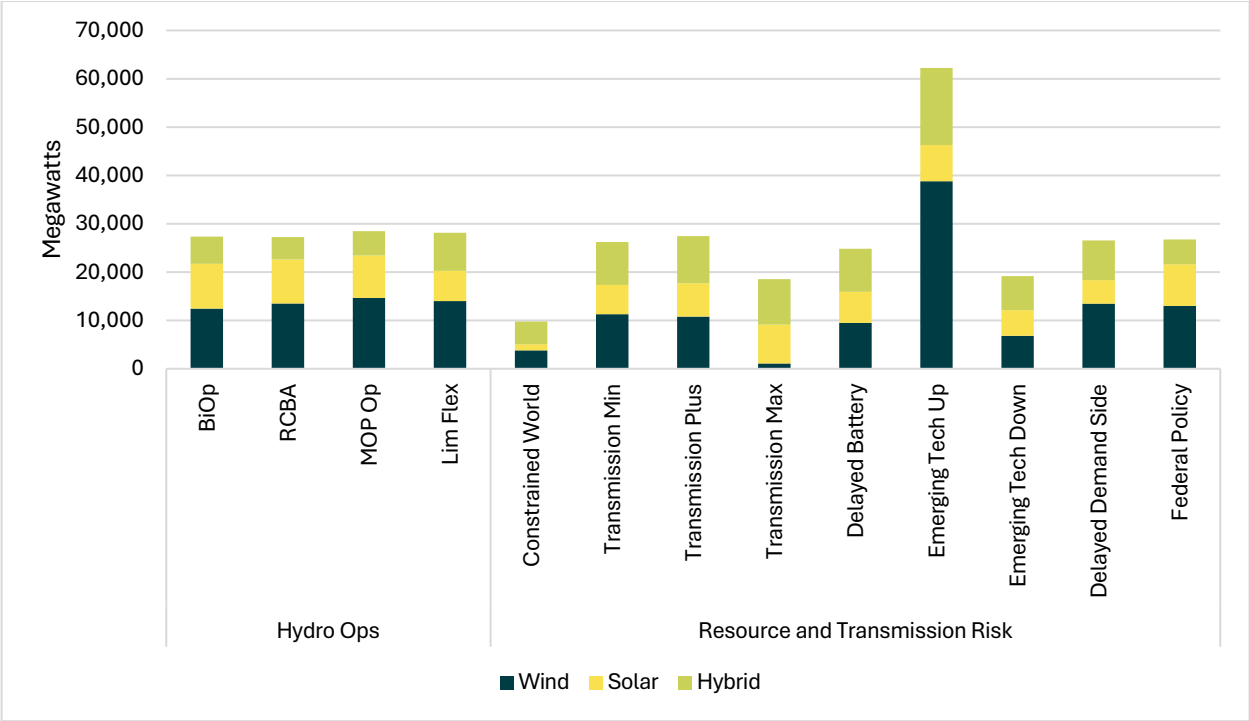


Figure N - 21: Renewable Build by 2046



The sensitivities that show differences in this trend connect back to the overall market studies results. For example, the Transmission Max sensitivity shows significantly more solar (particularly as a percentage of renewable build) than any of the other sensitivities. The main driver of this difference is

the market study and the amount of wind developed across the broader West, as discussed more in Technical Appendix L – Wholesale Market Availability and Results. With additional transmission connectivity, the market study developed more wind, particularly in the Mountain West, as this provided a more efficient way to meet loads and policy goals. This resulted in less solar being developed across the West. This shift in market study results then caused a shift in what the regional results developed to optimize diversity of renewable resources. Rather than further adding to the amount of West-wide wind, the model optimized with greater amounts of in-region solar to provide overall fuel diversity of renewables.

Storage

The Ninth Plan modeled a range of storage resources, including standalone battery storage, hybrid renewable resources (specifically solar plus battery storage), and two emerging technology reference plants. This section discusses the findings of standalone battery storage and hybrid systems.

Standalone battery storage and hybrid systems were selected in all sensitivities. In most sensitivities, the models selected 2,245 megawatts of storage in 2028 and never adds more of this standalone storage resource (see Figure N - 22). That 2,245 megawatts of storage represents planned projects that the Council identified as being available in the near-term. These are projects that have been announced, but are not yet under construction and therefore not included in the representation of the existing system as defined and described in Technical Appendix B – Existing System Parameters and Policies.

The sensitivities that add more standalone storage over time are those that tend to have more standalone renewables. For example, the four different Changing Hydro Operations sensitivities and Changing Federal Policy sensitivity all assume clean tax credits. These credits bring down the cost of renewable resources, making the pairing of standalone renewables and standalone storage a more economical path. The Emerging Technology Cost Increase sensitivity has significantly more wind than the other sensitivities, and these additional standalone batteries are providing some additional reserves to account for that added resource.

Figure N - 22: Short-Duration Storage Build in 2032 and 2046

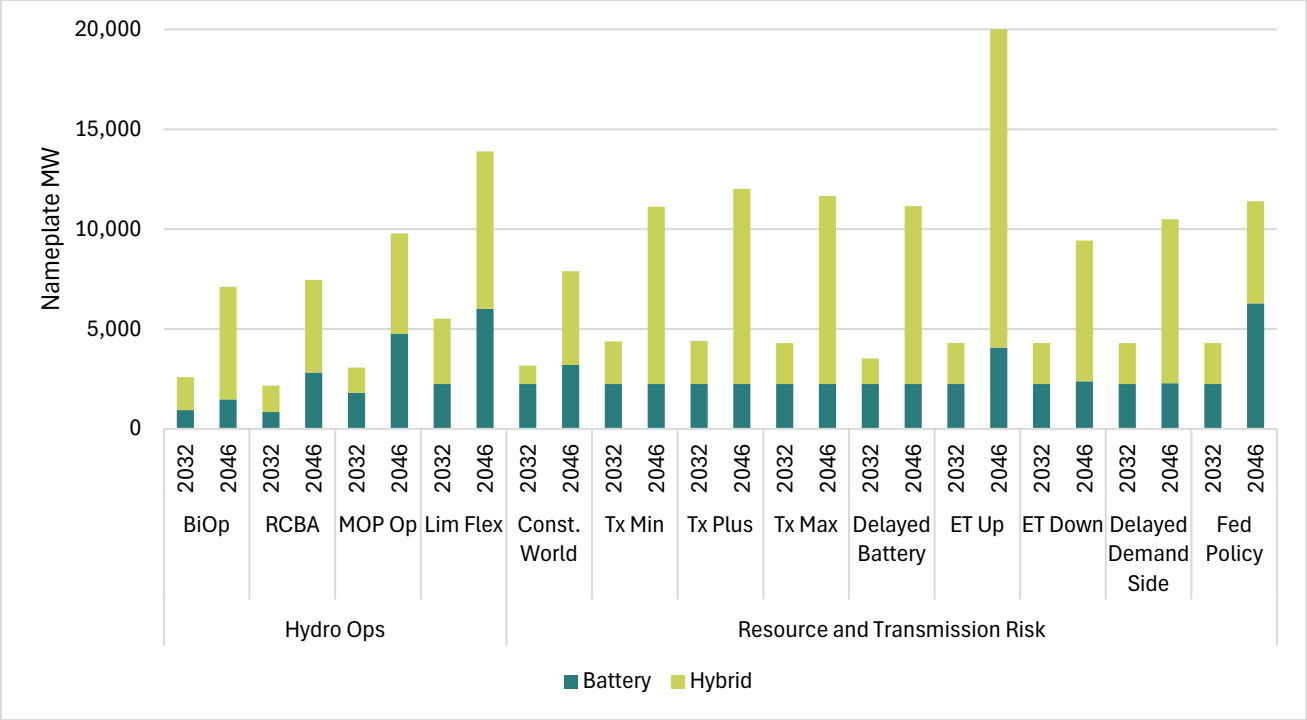
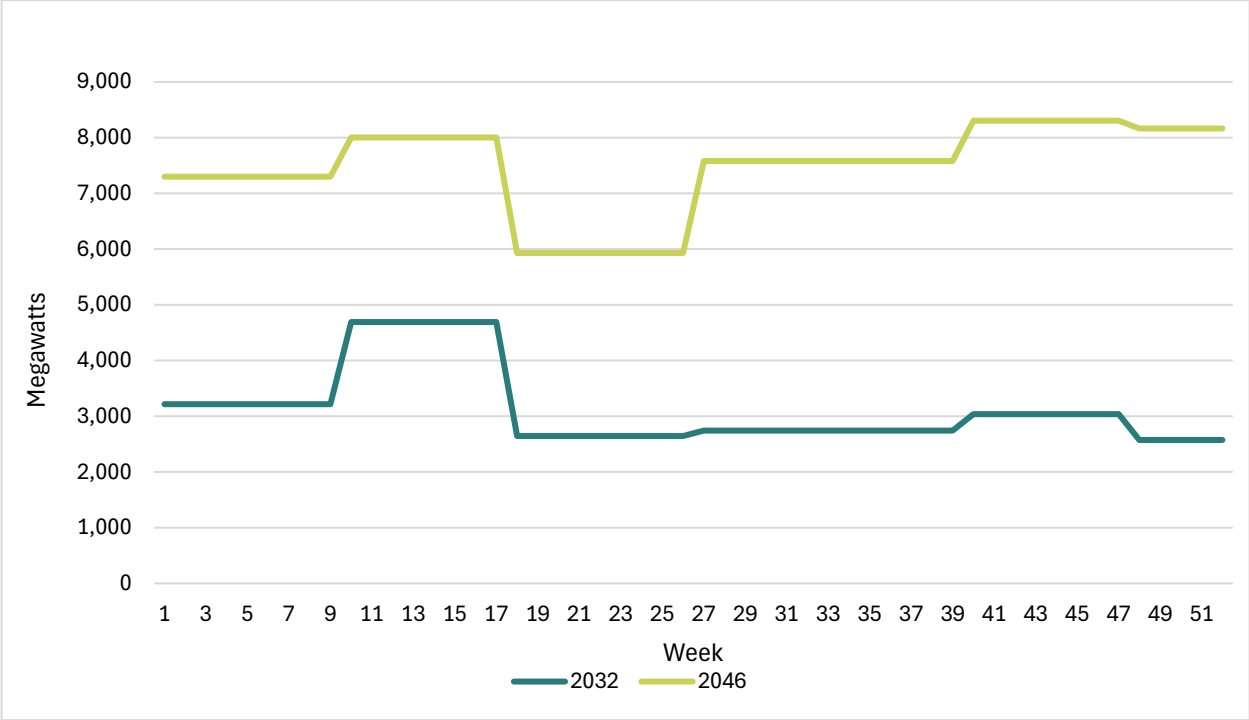


Figure N - 22 also shows that as storage is added to the system post 2028, it tends to be in the form of hybrid solar plus storage resources. This provides a way to bring the energy requirement for the system, while also meeting the flexibility and reserve needs.

One important feature of OptGen is the dynamic probabilistic reserves functionality. This functionality allows the model to dynamically adjust and solve for the reserve requirement over time as resources are added to the system. Particularly, as renewables are added to the system, greater amounts of reserves are required to account for the increased risk of uncertainty around fuel availability. This can be seen in Figure N - 23, which captures the reserves required for renewables in the Transmission Plus sensitivity. In this specific sensitivity, the model built 7,472 MW of variable energy resources by 2032 and 27,453 MW by 2046. That roughly 20,000 MW increase over the years required an additional roughly 4,000 MW of reserves. The specific amount varies by season.

Figure N - 23: Reserve Requirement for Renewables in Transmission Plus Sensitivity

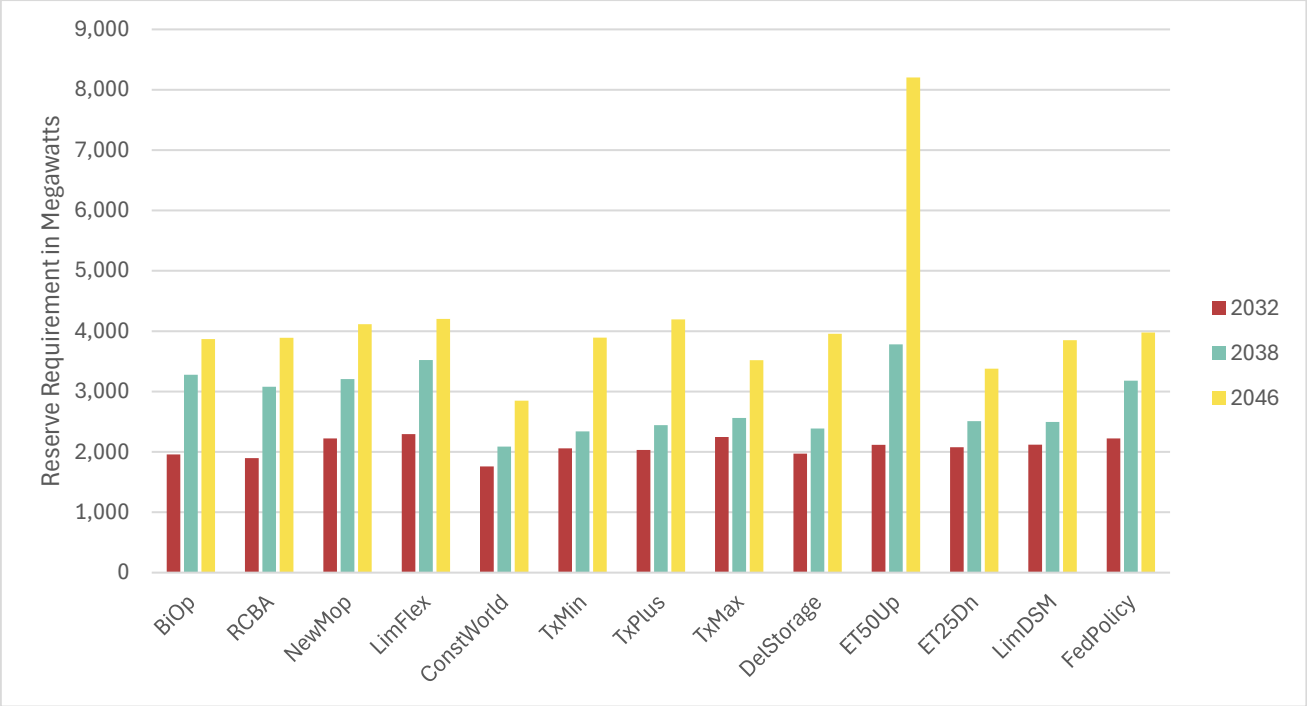


The new storage that is developed in the model is primarily used to provide reserves. The average reserve percentage across all sensitivities and zones in 2032 is close to 90%, although the specific amount varies by sensitivity, future, and zone.[14] In 2046, that average reserve percentage drops to closer to 70%.

Another example reflecting the association between short duration storage and its role in meeting reserve needs can be seen in Figure N - 25. Note the dynamic probabilistic reserve requirement (reserve requirement for renewables) is nearly twice as much during the Emerging Tech Cost Increase sensitivity per the observations above about the significant investment in wind and thus the investment in short duration storage as a resource to meet those reserve requirements. Similarly, when the balancing reserve requirement is less due to lower renewable investment in the Constrained Resources and Transmission sensitivity the short duration storage investment is also less.

[14] Reserve percentage refers to the percent of the batteries nameplate capability that is used for reserves.

Figure N - 24: Average Annual Dynamic Probabilistic Reserve Increasing Over Time



Natural Gas

As discussed in Technical Appendix G – New Generating Resources, the Council modeled three natural gas technologies: combined cycle combustion turbine, simple cycle combustion turbine, and a reciprocating engine. The model selected natural gas in all sensitivities, predominantly peakers (simple cycle and recip technologies), particularly in the earlier years of the study. The overall build by 2032 and 2046 is in Figure N - 25 and Figure N - 26, respectively.

Figure N - 25: Natural Gas Build by Sensitivity for 2032

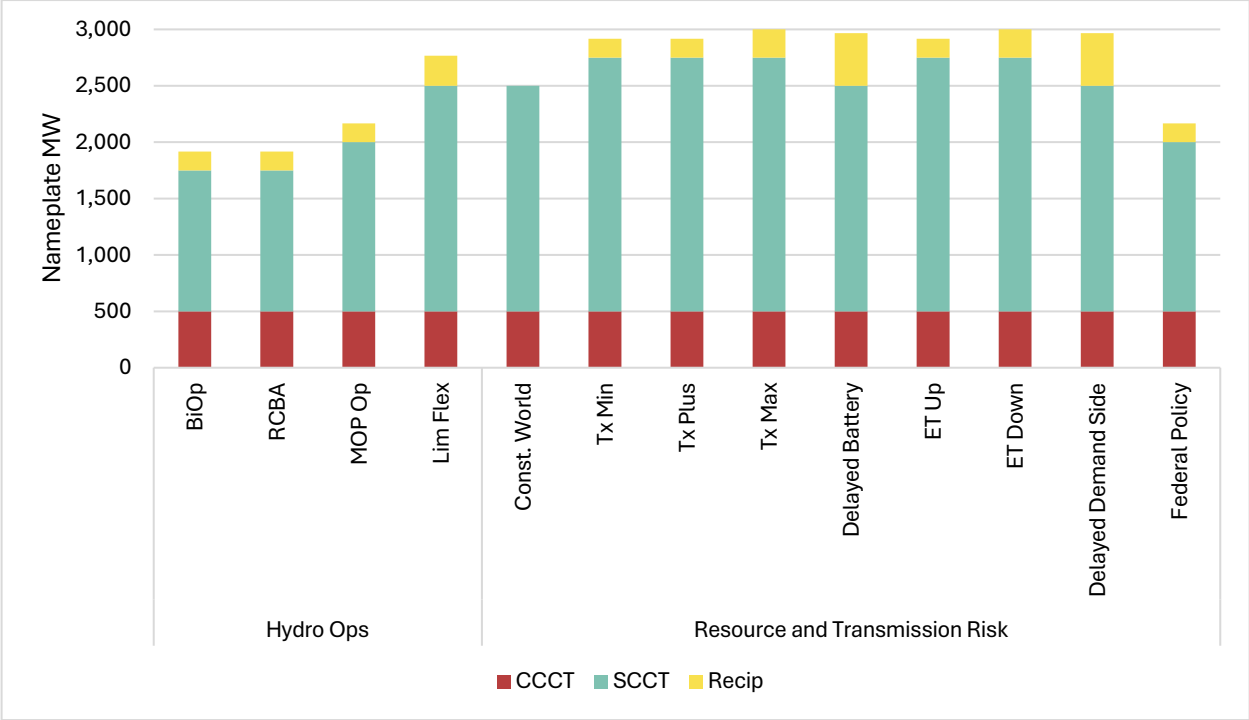
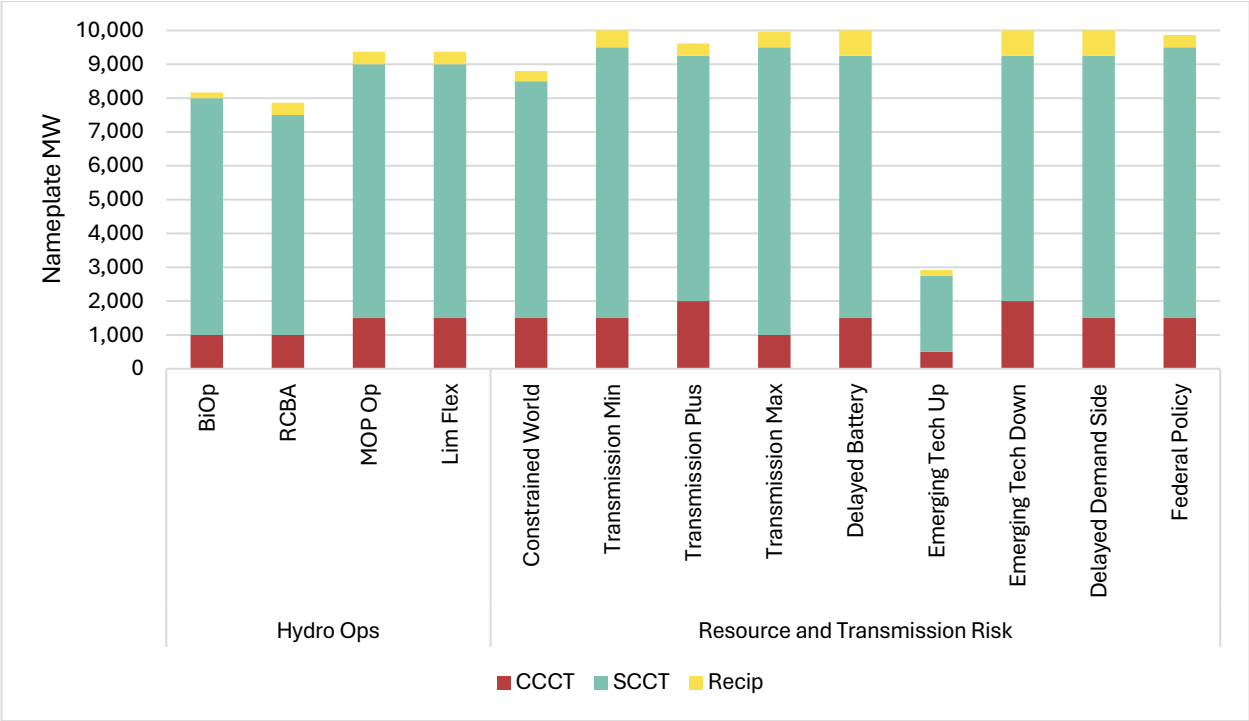


Figure N - 26: Natural Gas Build by Sensitivity for 2046



To account for existing constraints in the natural gas pipeline system, the Council assumed a 3,000 MW limit of new gas by 2032. That limit was expanded to 10,000 MW, essentially the existing system capacity, after 2032. As is clear in the above two figures, the model selects up to the limit for natural

gas across many of the sensitivities. The one notable exception in the long-term is the Emerging Technology Costs Up sensitivity. In this specific sensitivity, the overall market build is driving a different result for the region. To meet clean policies West-wide with assumed increases in emerging technology costs, the market study developed more resources in the Northwest zone. Those resources were removed from the West-wide market buildout that was then provided to OptGen, resulting in a larger resource whole in the Northwest. This resulted in a build of significantly more renewable resources in the region (see Figure N - 21) as a way to meeting West-wide policy requirements. Additionally, also in this sensitivity, outside the region more gas resources were developed, which also may have dampened the signal for gas resources inside the region.

Natural gas utilization is an important element in understanding the overall role that new natural gas is playing in the system. The utilization of natural gas is a combination of generation and reserves. The Ninth Plan modeling shows a couple of general trends:[15]

- **New natural gas is primarily utilized for reserves**: The new units added to the system generally show greater utilization for reserves. This is particularly true in Washington, but the trend holds for the new units in Idaho and Montana. Considering the bulk of these new units are peaker plants, this makes sense. The modeling does show that the Idaho Power zone, the zone that acquired the combined cycle unit by 2032, utilizes the new gas more for generation.
- **New natural gas generates more in low hydro conditions**: When digging into the utilization across futures, the new natural gas units show the highest generation in futures with the lowest hydro or years with the highest net loads (combination of loads minus existing generation from variable energy resources). This suggests that these peaking plants provide a good hedge against low hydro conditions.
- **Existing natural gas is more often utilized for generation**: Much of the existing natural gas consists of combined cycle units. These tend to be more efficient, less flexible units. The modeling shows that, generally, the existing system is being utilized more for generation, although there are still some levels of reserves held on these units.
- **Existing natural gas generates more in low hydro conditions and high loads**: The existing system is utilized more in futures with low hydro (similar to the new units) as well as high loads, including futures with high loads *and* high hydro. These higher loads, particularly in the near-term, are primarily from large loads like data centers, which tend to be relatively flat, benefiting from more of an energy resource than a peaking one.

[15] This is discussed in more detail in April 28, 2026 work session: https://nwcouncil.box.com/v/April29-PowerPlanWorkSession

Conventional Geothermal

Due to the timelines for identifying and developing the resource, conventional geothermal was not available to the model until 2034. Geothermal was selected in every sensitivity once available to the model (see

Figure N - 27) and generally selected more geothermal through the end of the study, hitting the maximum allowed in some sensitivities, as represented by the dashed line in Figure N - 28. These results show a robust signal for the role that conventional geothermal can play in meeting system needs. This suggests that if more geothermal potential were available at a cost competitive price point, that it might provide even greater value for the system. This is explored more in the discussion of the results around the emerging technologies below.

Figure N - 27: Geothermal Build Across Sensitivities in 2034

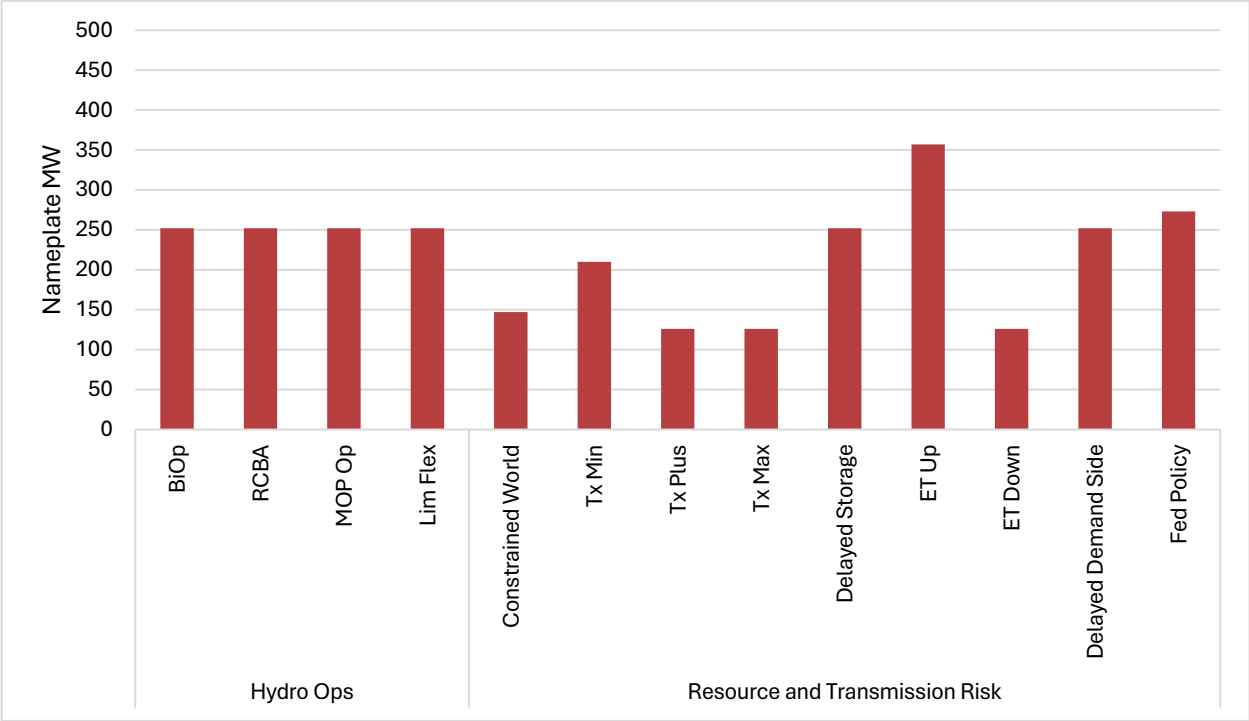
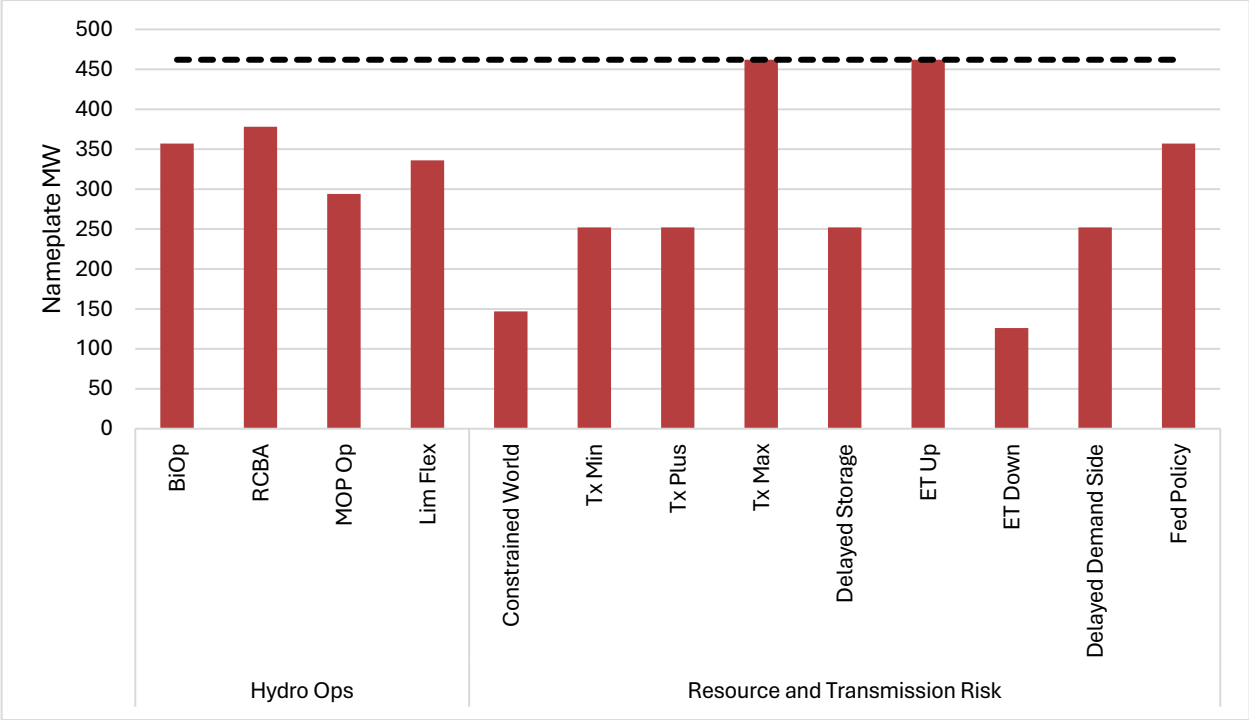


Figure N - 28: Geothermal Build Across Sensitivities by 2046



Emerging Technology Resource Themes

The Ninth Plan modeled three different emerging technology reference proxy plants to provide insight around what potential resource attributes will provide value to the system in the long term. This includes:

- Clean Long Duration Storage Proxy: Helps the grid better integrate variable resources, provides operational flexibility, and offers demand shifting on a seasonal scale. Represented by an iron-air battery.
- Clean Peaker and Medium Duration Storage Proxy: Mitigates high peak demand, while extending operational flexibility and shorter term, daily/hourly demand shifting. Represented by a hydrogen peaker plant with on-site production and storage.
- Clean Baseload Proxy: Offers reliability and firm supply to the grid. Represented by a small modular nuclear reactor.

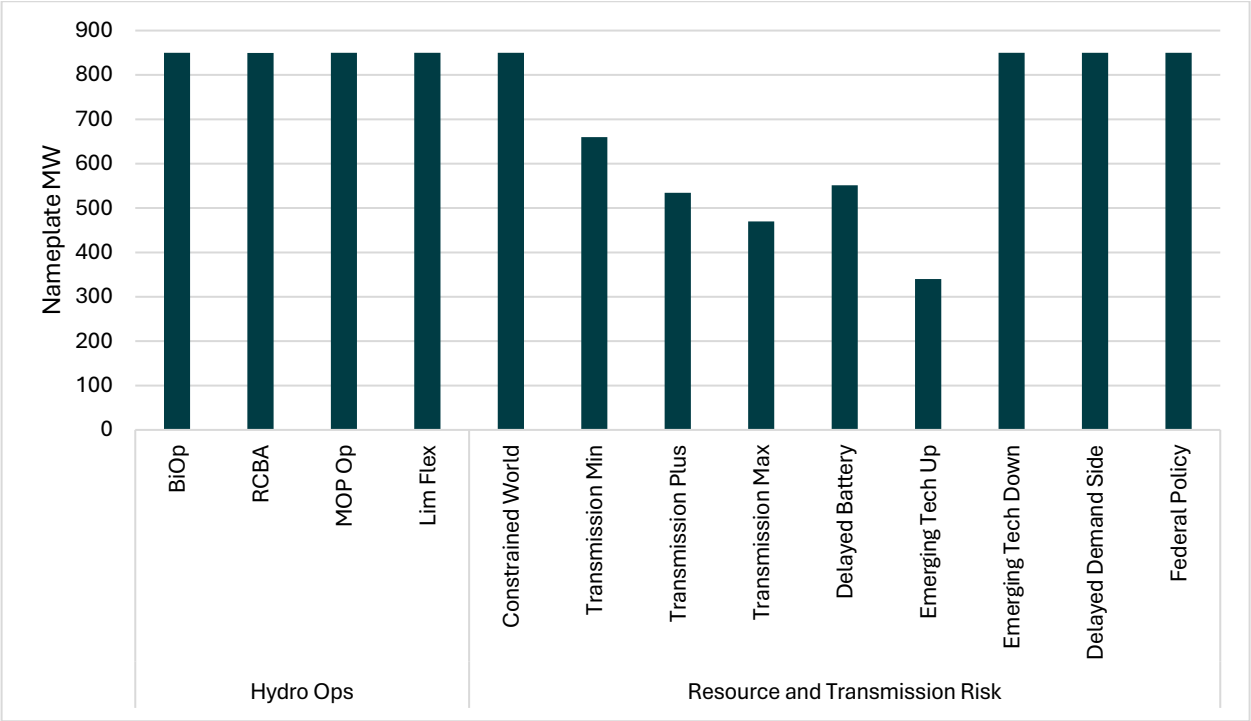
All of these resources were selected by the model, with the storage resources being selected in all sensitivities in which they were available, and the clean baseload proxy being selected in roughly 60% of the sensitivities. This section provides more information about the modeling results of these resources.

Clean Long-Duration Energy Storage Proxy

Clean long-duration energy storage was available to the model starting in 2032 for all sensitivities, except for the Constrained Resource and Transmission Risk sensitivity when the availability timeline was pushed out 10 years to 2042. This resource was selected in all sensitivities by the end of the study. The model selected this resource as soon as it was available in all sensitivities, except for the Emerging Technology Costs Up sensitivity, in which the costs were increased by 50%.

The maximum buildout allowed for this resource in the modeling was 850 MW. Most sensitivities hit this build limit (see Figure N - 29). These highest build sensitivities include those where there was either generally larger amounts of renewables and/or less natural gas. The Hydro Operations sensitivities and Changing Federal Policy sensitivity assume tax credits for renewable resources and as a result these sensitivities generally build larger amounts of renewables and less natural gas. In those cases, a resource that provides long-duration storage brings value by supporting integration and seasonal shifting. The other sensitivities where more long-duration storage is acquired are those that have constraints in other resources (either all supply-side through the Constrained Resource and Transmission Risk or on the demand side with the Delayed Demand Side) or in the sensitivity when the costs all emerging technologies are decreased by 25%.

Figure N - 29: Long-Duration Storage Build by 2046



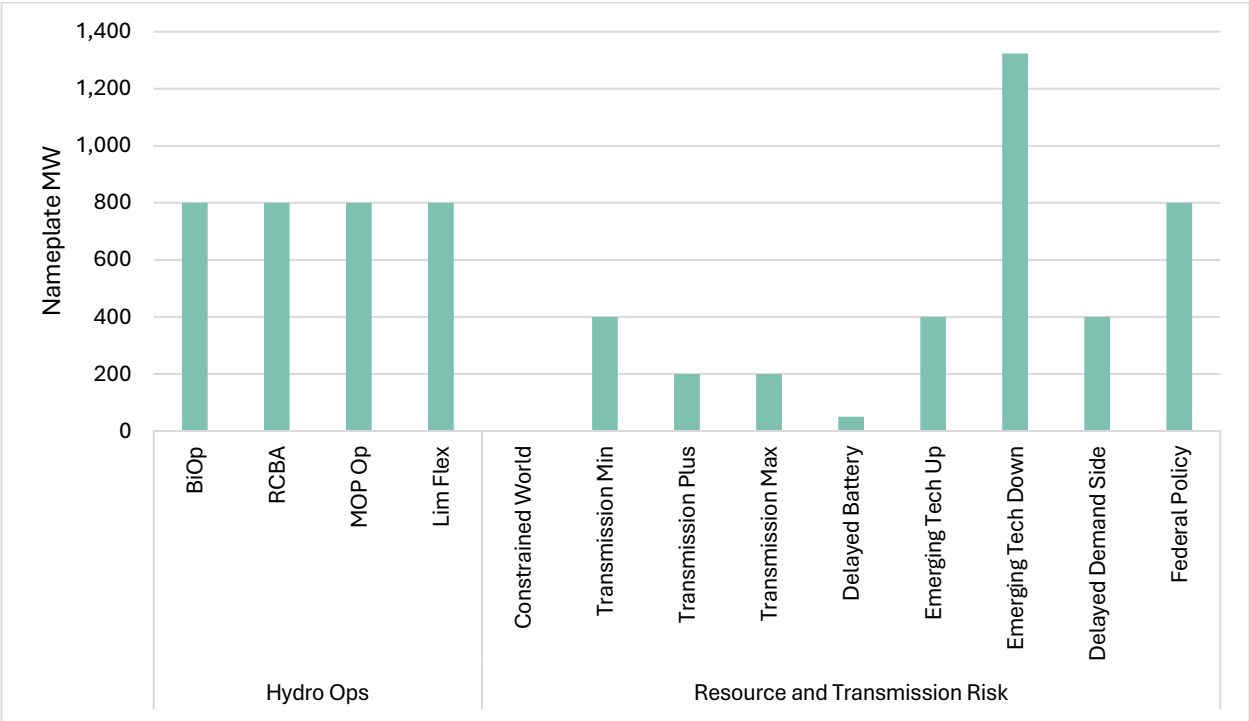
Clean Medium-Duration Energy Storage/Peaker Proxy

The clean medium-duration storage/peaker proxy reference plant was first available to the model in 2042, except for in the Constrained Resource and Transmission Risk sensitivity when all emerging technologies were delayed by 10 years resulting in this reference plant not being available within the

plan timeframe. This resource was generally selected in the first year it was available to the model and selected in all sensitivities for which it was an option by 2046.

Similar to the long-duration energy storage, the model selected more of this proxy reference plant in sensitivities that generally had higher renewable builds and lower natural gas builds driven by differences in federal policy (the Changing Hydro Operations sensitivities and the Changing Federal Policy sensitivity). The model also selected significantly more in the sensitivity that decreased the emerging technology costs by 25%. Given the overlap in results between this and the clean long-duration storage proxy resource described above, it is possible that if a higher limit (or no limit) were placed on the clean long-duration storage resource, less medium duration storage would have been acquired.

Figure N - 30: Clean Medium Duration Storage Build by 2046



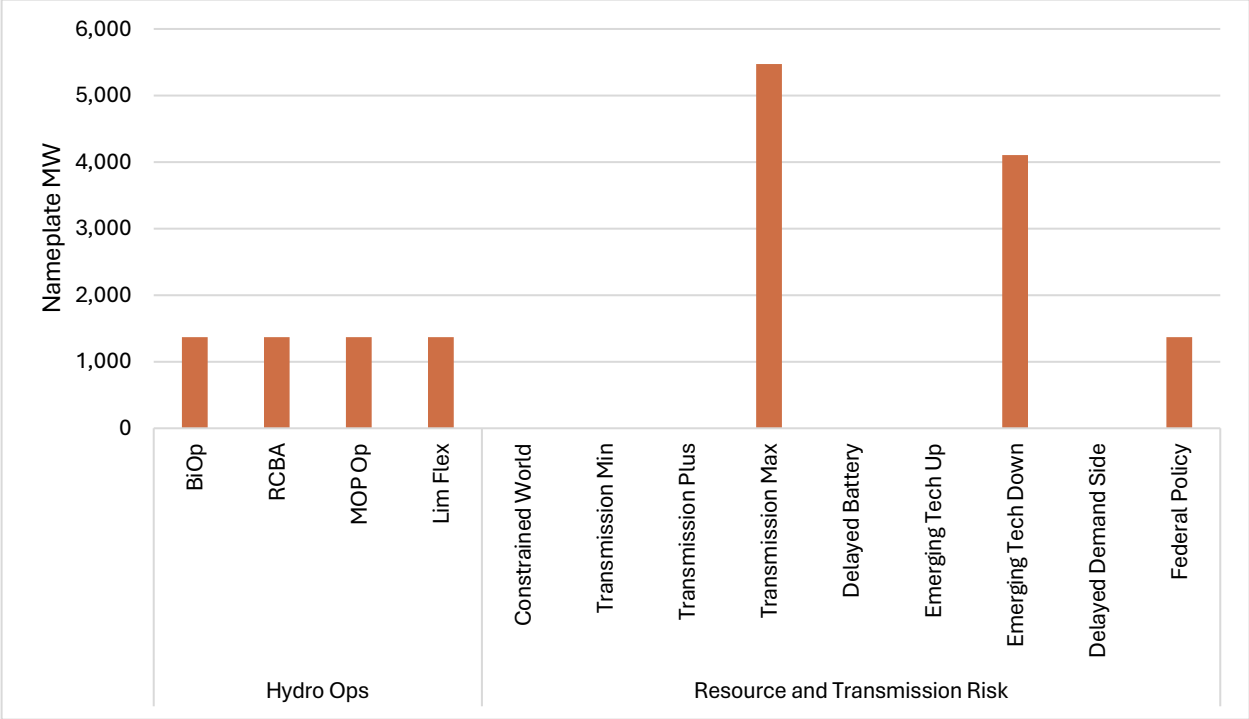
Clean Baseload Proxy

The clean baseload proxy reference plant was available to the model starting in 2042 in all sensitivities, except the Constrained Resource and Transmission Risk sensitivity in which the resource was not available within the study horizon. Unlike the other emerging technology proxy resources described above, the model did not select the clean baseload proxy in any sensitivity when it was first available (in 2042). The resource was, however, selected in seven of the sensitivities in 2046, always in Washington.

The results for the clean baseload proxy show similar themes to the other emerging technologies (see Figure N - 31). This resource is selected in the five sensitivities that have tax credits for renewables, resulting in both an increase in renewable builds and a decrease in total natural gas builds. In these

cases, this resource provides additional baseload energy to the system. Consistent with all three emerging technologies, the model also selects more of this resource in the sensitivity when the costs come down by 25% (Emerging Technology Costs Down). In a departure from the other emerging tech results, the sensitivity with the largest build of the clean baseload proxy is the Transmission Max sensitivity. In this sensitivity, the west-wide market study had a larger overall build in the Pacific Northwest. When those resources were removed for the final stage of modeling in OptGen, there was a bigger hole in the west-wide need for meeting adequacy and clean policies. This resulted in a very different regional buildout, with the lowest natural gas build (3,000 MW by 2046), and a shift in the wind/solar build balance with the lowest wind build and highest solar build.

Figure N - 31: Clean Baseload Build in 2046



Remaining Resource Themes

As noted above, only three resources were not selected in a robust way across the sensitivity analysis. This section provides more on those findings.

Offshore Wind

Offshore wind was available to the model starting in 2035. The total potential for this resource in the region is 3,000 MW. This is informed by the lease area descriptive statistics for the two identified zones off the Oregon coast. Of the 3,000 MW potential, only 235 MW of this resource was selected by the model in 2046 in the Transmission Max sensitivity. As discussed above, this sensitivity required significantly more clean resources to be developed in the region to meet adequacy and clean policies. Under this condition, offshore wind became a viable resource to add to the mix.

Pumped Storage

Pumped storage was available to the model starting in 2029. The Ninth Plan estimate of potential for the region was 4,000 MW. Of this potential, the model selected only one reference plant, at 400 MW, in 2034 in the Constrained Resource and Transmission Risk sensitivity. In this sensitivity, the two clean emerging technology proxy resources were delayed 10 years, which resulted in long-duration energy storage not being available until 2042 and medium-duration energy storage not available in the study. In this case, when that resource was not available, the model deferred to pumped storage as a longer duration storage resource.

Rooftop Solar

The Ninth Plan is the first to model rooftop solar as a resource option.[16] The goal was to understand whether, and under what circumstances, this resource would be part of a cost-effective resource strategy for the region. Rooftop solar was selected in only one sensitivity, the Constrained Resource and Transmission Risk sensitivity. This sensitivity significantly limited the availability of supply side resources and increased the costs of those resources. Under these constraints, the model selected more demand side resources of all types to support resource adequacy. This includes acquiring all available conservation, selecting all of the frequently deployable demand response, and selecting rooftop solar. This result suggests that rooftop solar can be a cost-effective way of supporting resource adequacy if there are challenges in acquiring supply side resources. It also suggests that, when available, supply side resources are a lower cost option for meeting power system needs.

Market Price Results

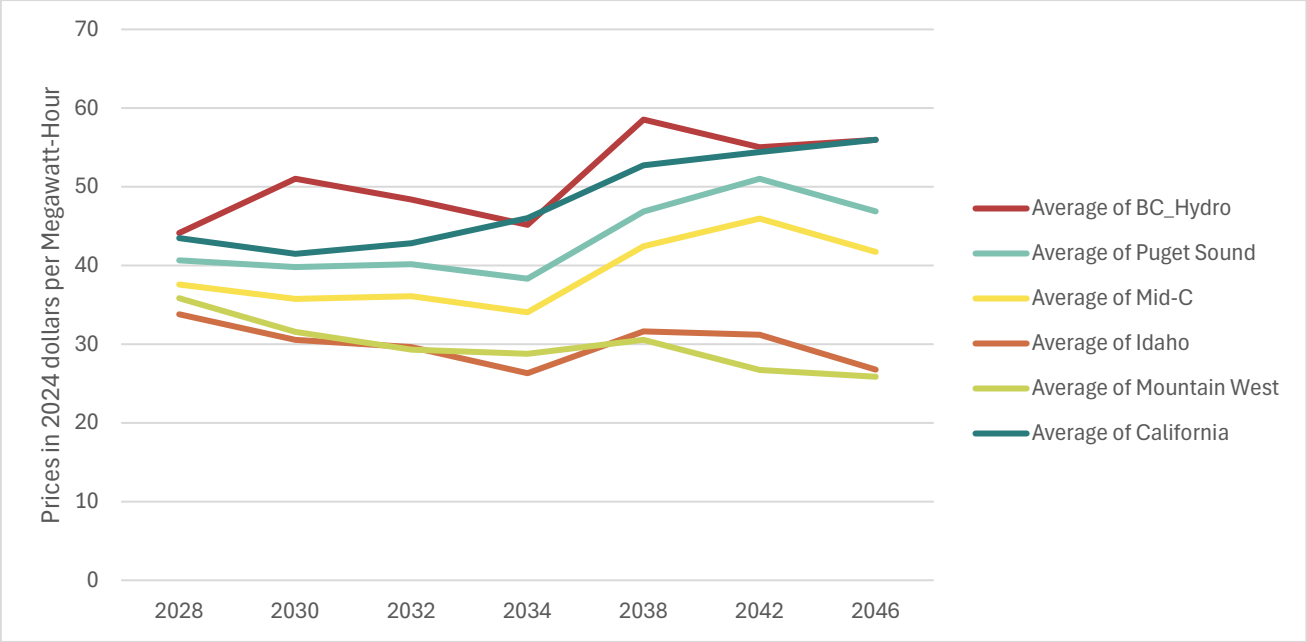
Themes

Market prices on an annual and seasonal basis tend to follow a few themes that are discussed in more detail in Technical Appendix L – Wholesale Market Availability Results. Annual average wholesale market prices over all the sensitivities slightly increase in the middle and western parts of the region and slightly decrease in the eastern part of the region as seen in Figure N - 32.[17] These trends track with out-of-region prices, the prices nearer the load centers on the west coast slightly increase and prices near more of the development of high capacity factor renewable generation with lower loads in the interior of the WECC slightly decrease.

[16] Previous power plans accounted for rooftop solar in the load forecast. As discussed in Technical Appendix E and Technical Appendix J, for the Ninth Plan some rooftop solar naturally occurring is captured in the load forecast, with the remainder captured in the supply curves as potential.

[17] Associated with OptGen regional buildouts and production cost simulation for the WECC rather than AURORA prices as reported in Technical Appendix L.

Figure N - 32: Annual Wholesale Prices Over Time



The price of market imports and the value of market exports, in addition to the cost of meeting regional demand, is a key piece in the economics of an investment strategy. Often comparing regional to neighboring region prices can be useful to see some of the key economic signals that drive market imports and exports without examining the load resource balance in both regions. Seasonal price differentials between the region and neighboring regions for the most part maintained recent historical trends throughout the sensitivities with a few exceptions.

In all sensitivities, annual regional prices depend on future conditions. Low hydro runoff conditions and high loads resulted in high prices, and high runoff conditions and low loads resulted in low prices as can be seen in Figure N - 33 through Figure N - 38. The different sensitivities seem to slightly change dependency on future conditions primarily when Emerging Technology Costs are increased and the west-wide market conditions depend more on the buildout in the region.

For Mid-Columbia and Puget Sound prices, this spread increases over time as can be seen by the difference between 2032 prices in Figure N - 33 and Figure N - 37 and 2046 prices in Figure N - 34 and Figure N - 38, respectively. This shows that for the westside and center parts of the region, prices vary more due to fuel and demand risk which is represented in the future conditions tested.

However, the Idaho price spread does not change much, as can be seen in by the difference between 2032 prices in Figure N - 35 and 2046 prices in Figure N - 36. Additionally, the smaller price spread in Idaho implies eastside prices are less dependent on the future condition likely due to more fuel diversity of supply resources.

Figure N - 33: Mid-Columbia Prices in 2032 by Future and Sensitivity

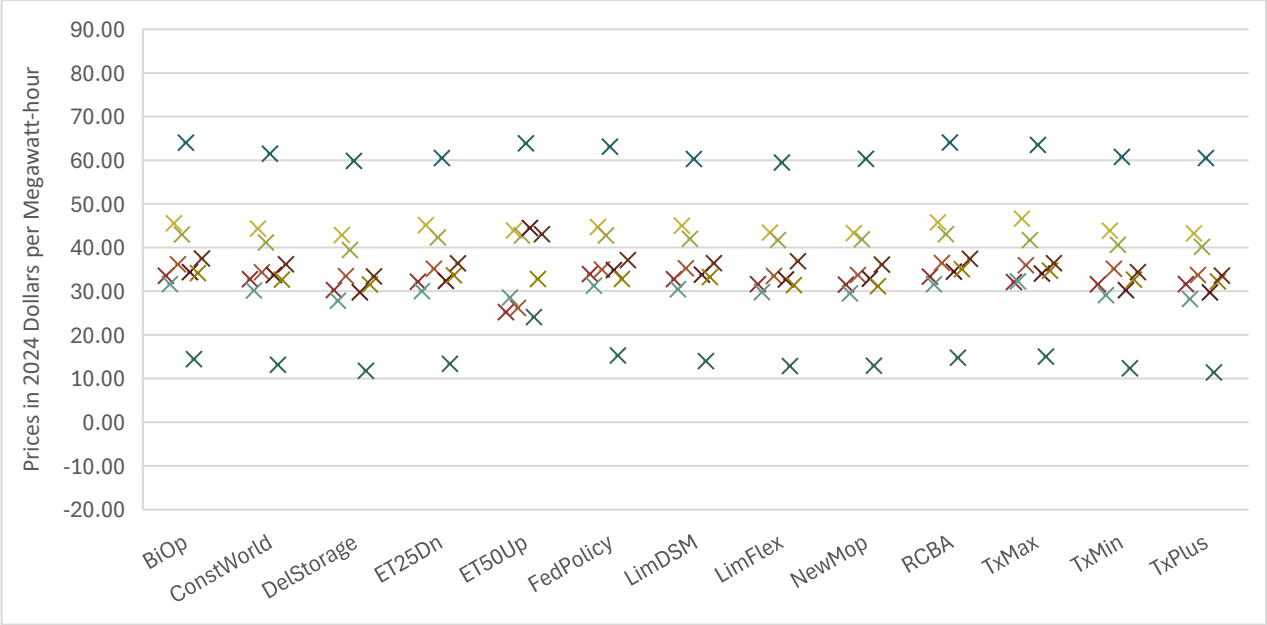


Figure N - 34: Mid-Columbia Prices in 2046 by Future and Sensitivity

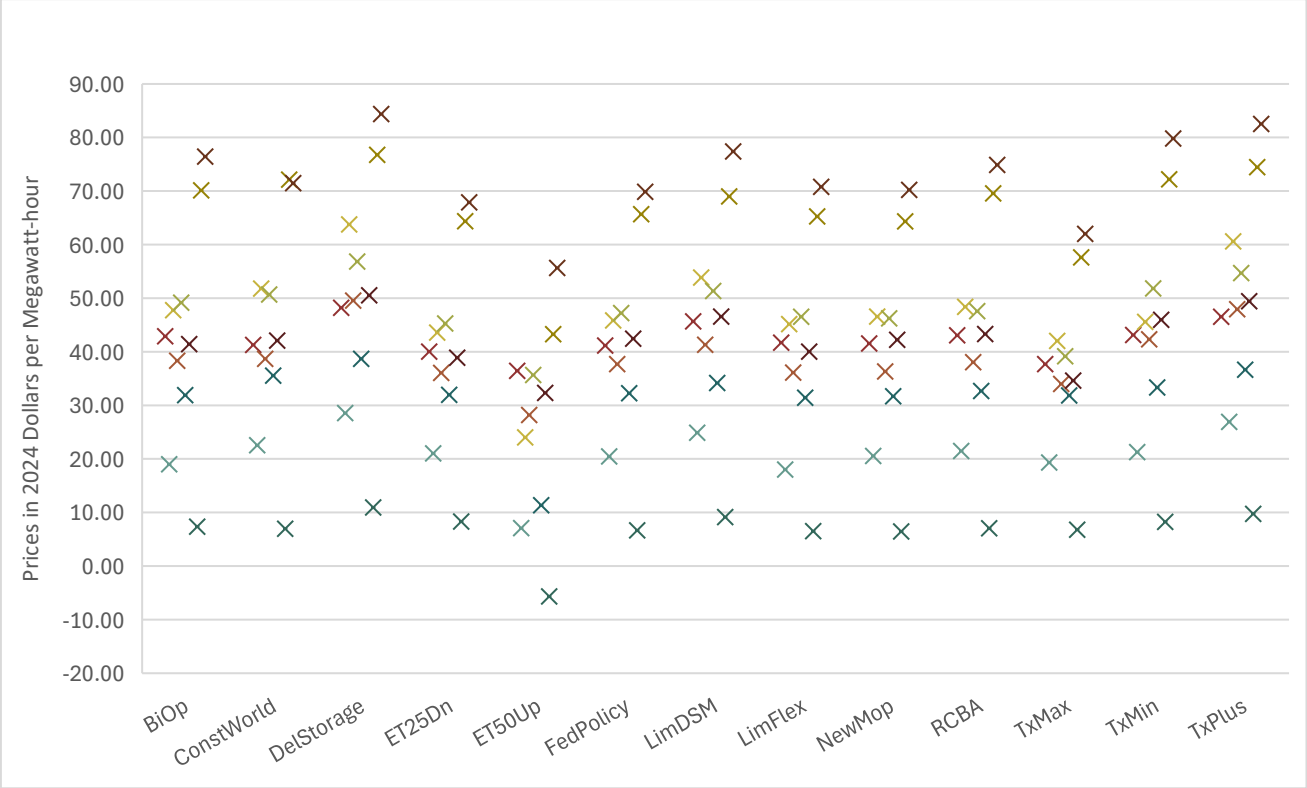


Figure N - 35: Idaho Prices in 2032 by Future and Sensitivity

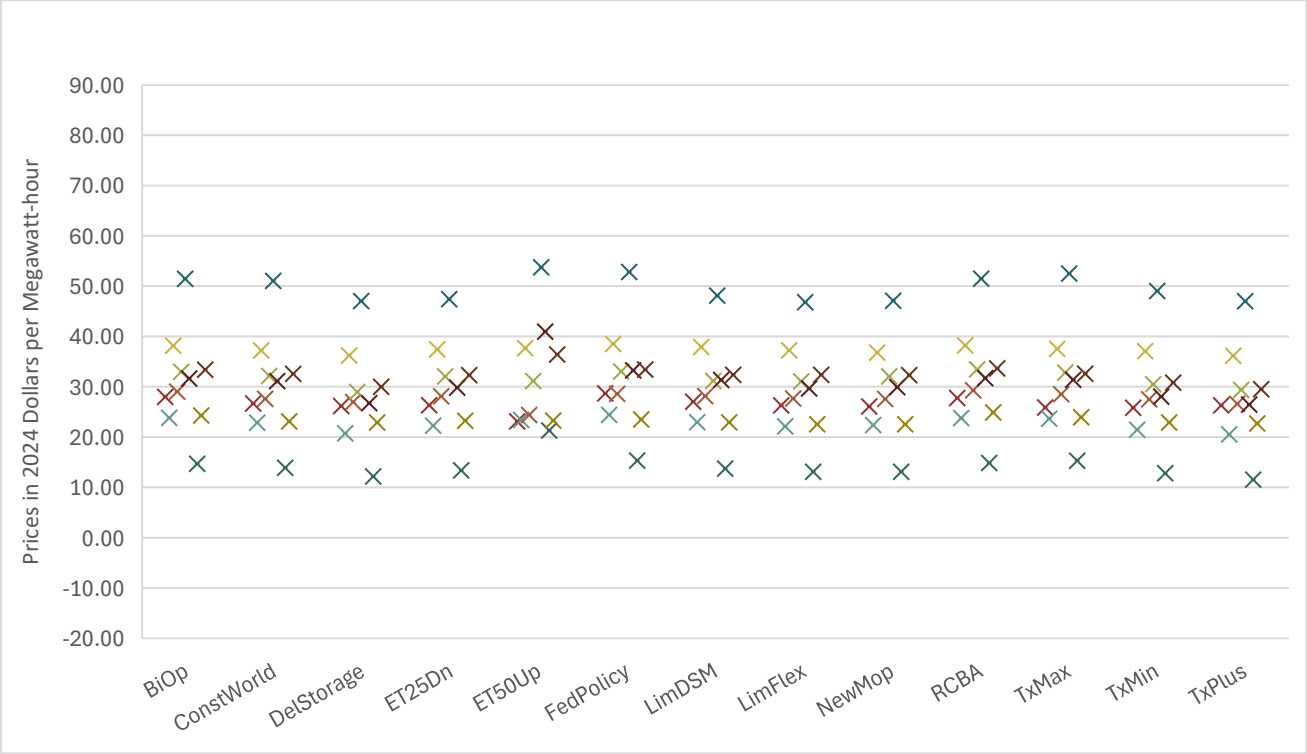


Figure N - 36: Idaho Prices in 2046 by Future and Sensitivity

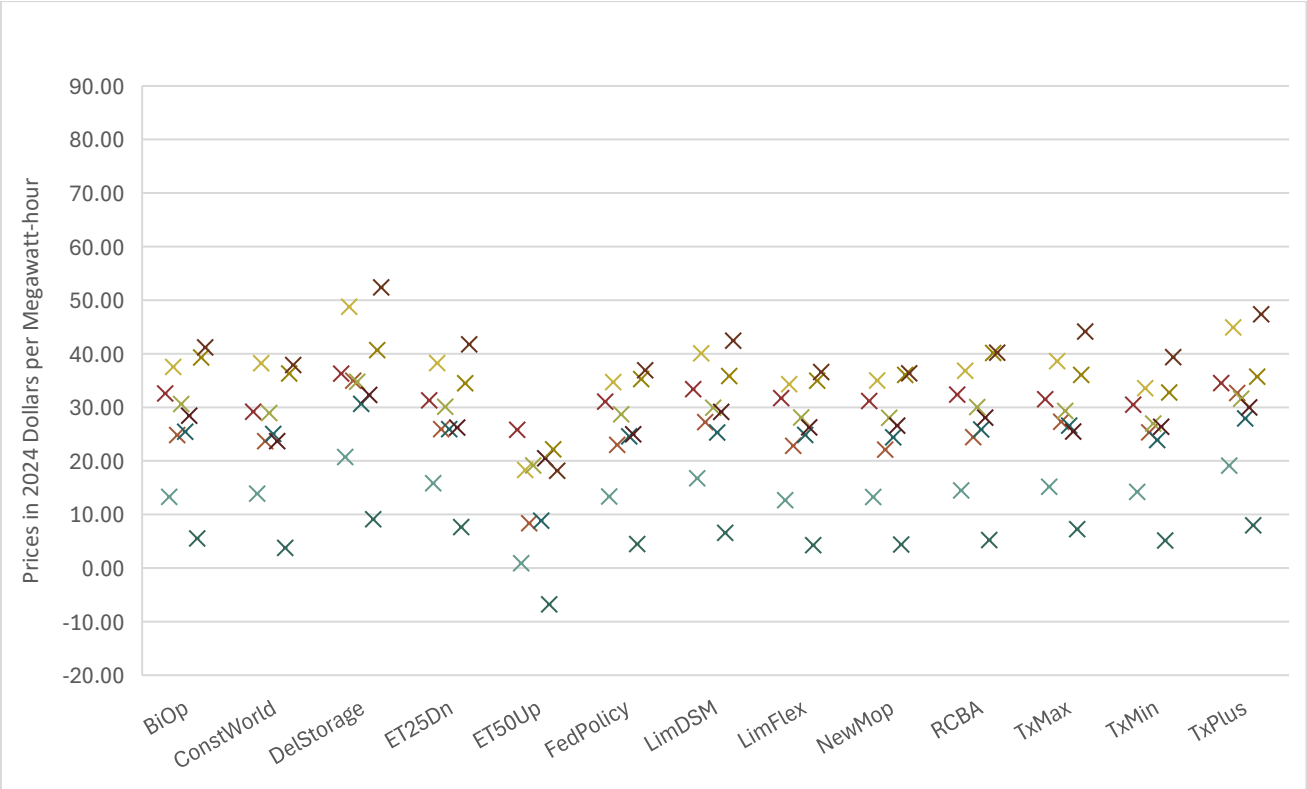


Figure N - 37: Puget Sound Prices in 2032 by Future and Sensitivity

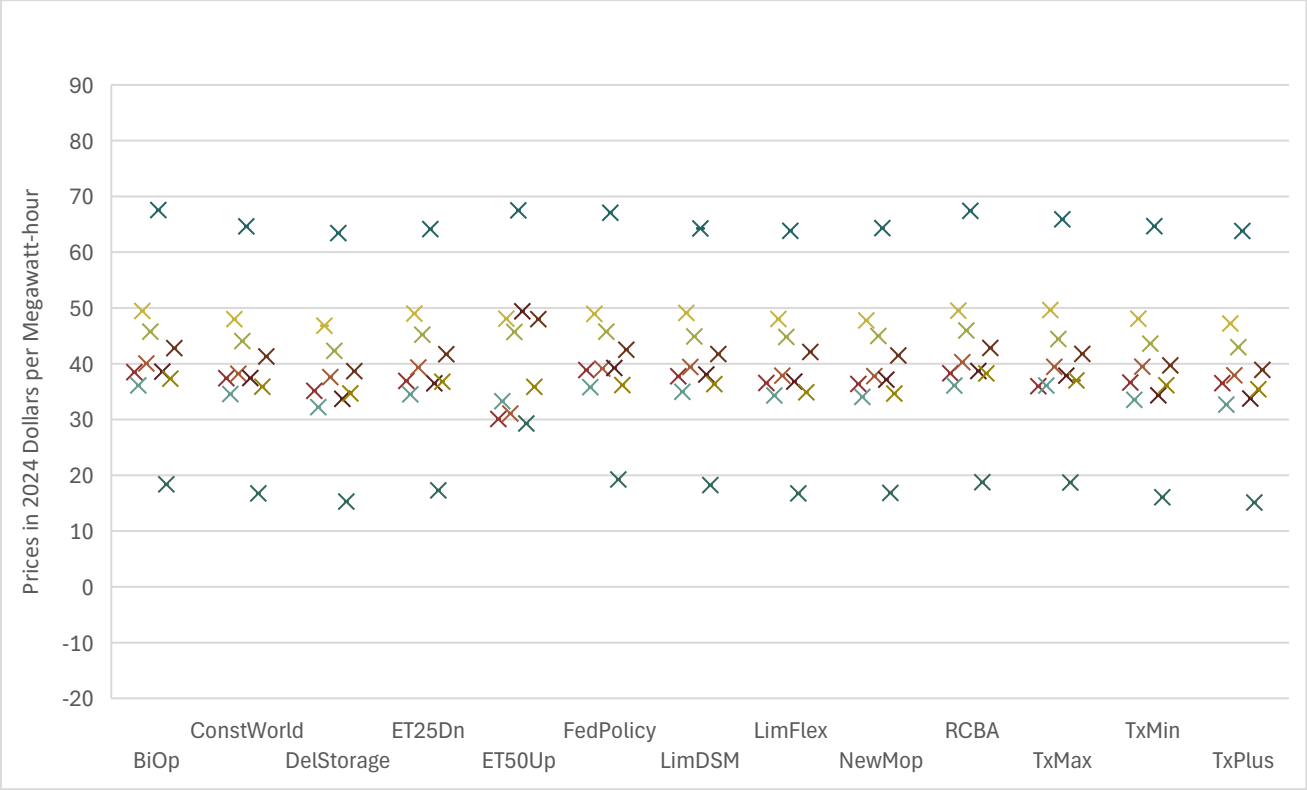
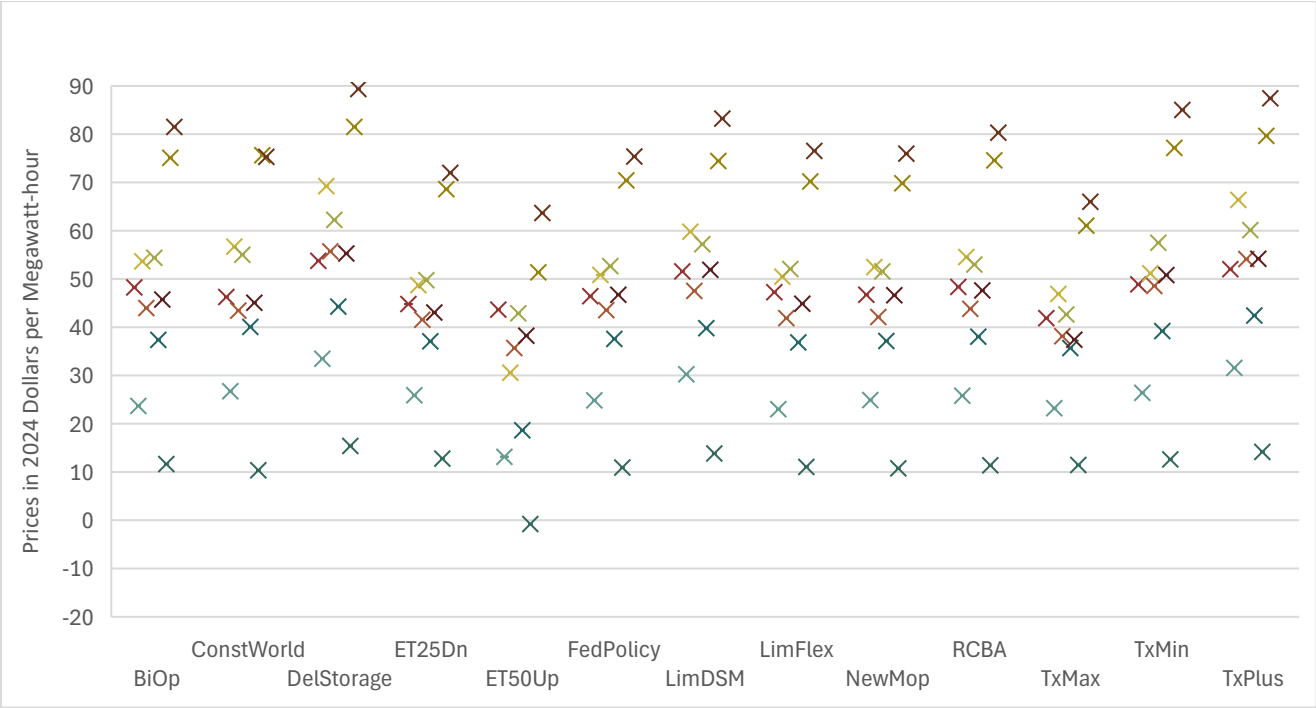


Figure N - 38: Puget Sound Area Prices in 2046 by Future and Sensitivity



Outside of the Mountain West and Idaho, winter prices increased over time, particularly the lower midday prices as can be seen in Figure N - 39 and Figure N - 40. This implies that some of the market value in the middle of the day due to solar builds outside the region tends to lessen over time. More specifically, the value to the region of importing less expensive power midday decreases, which likely improves the value of resources that provide power during that period in the latter years of the plan.

Figure N - 39: Winter Prices in 2032

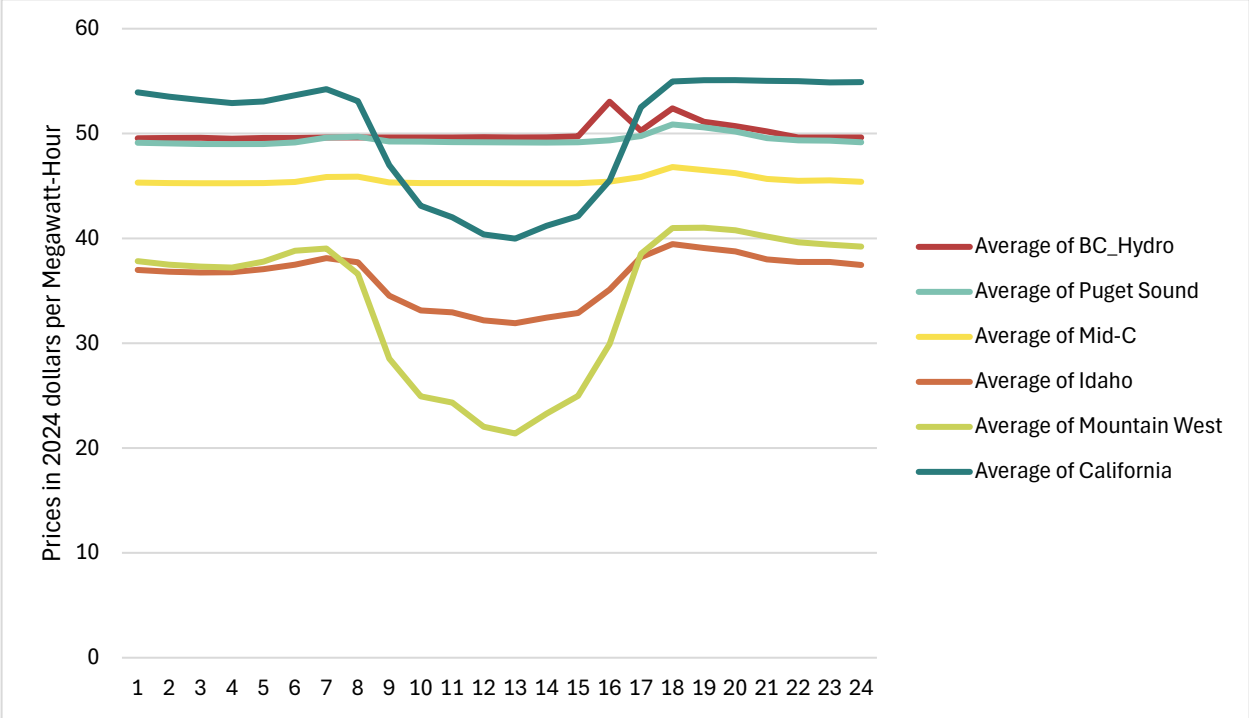


Figure N - 40: Winter Prices in 2046

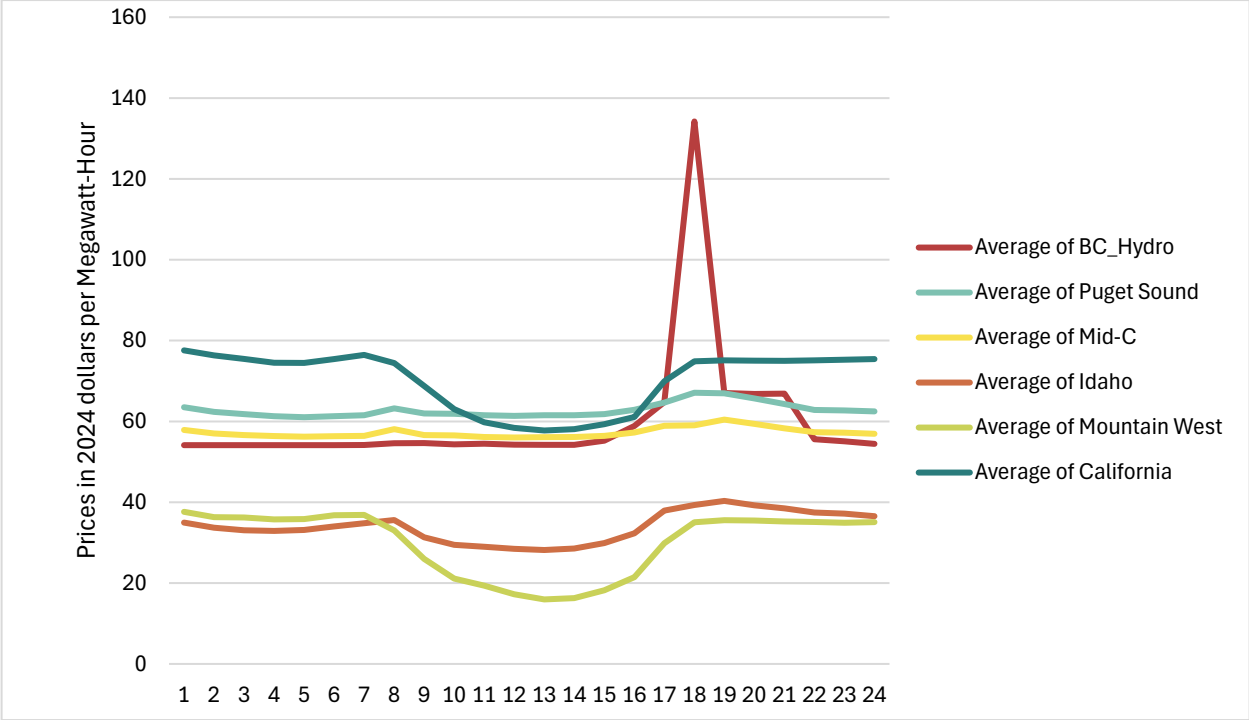


Figure N - 41: Summer Prices in 2032

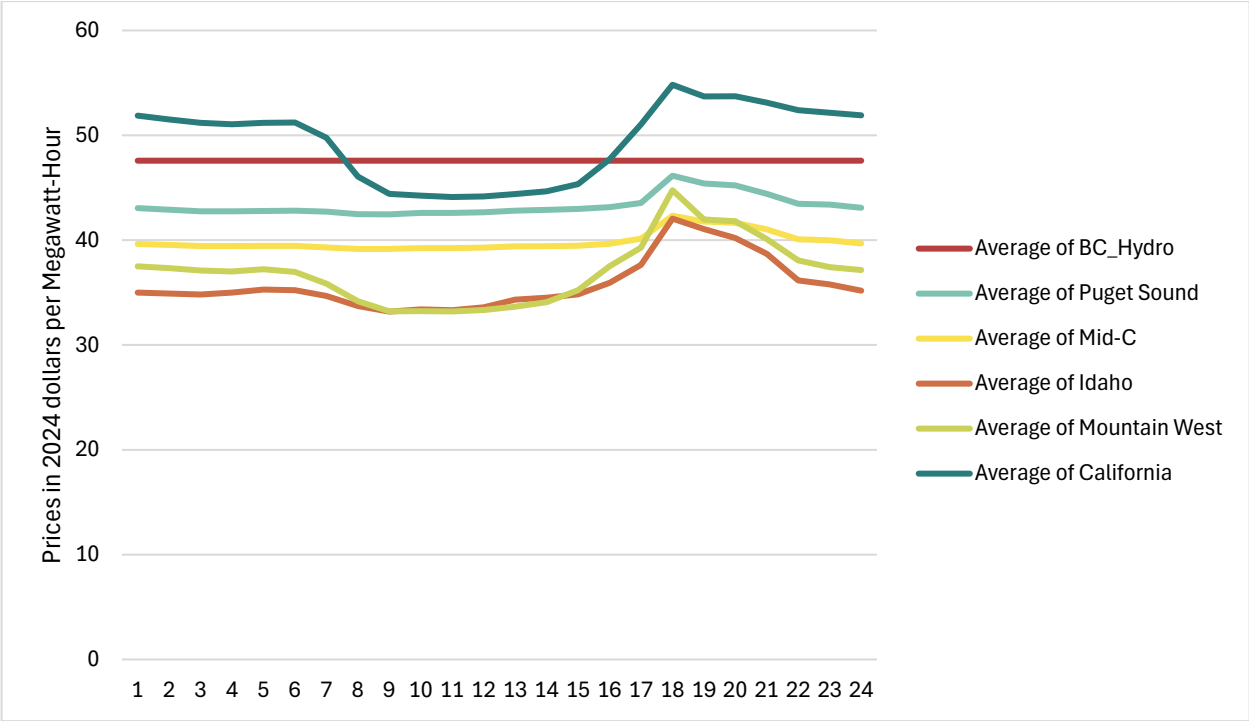


Figure N - 42: Summer Prices in 2046

Summer peak prices in the evening ramp go up everywhere over time. Since the WECC is summer peaking in general this is to be expected, but interestingly some parts of the region that were traditionally winter peaking are now seeing similar peak prices in winter and summer on average.

Figure N - 43: Spring Prices in 2032

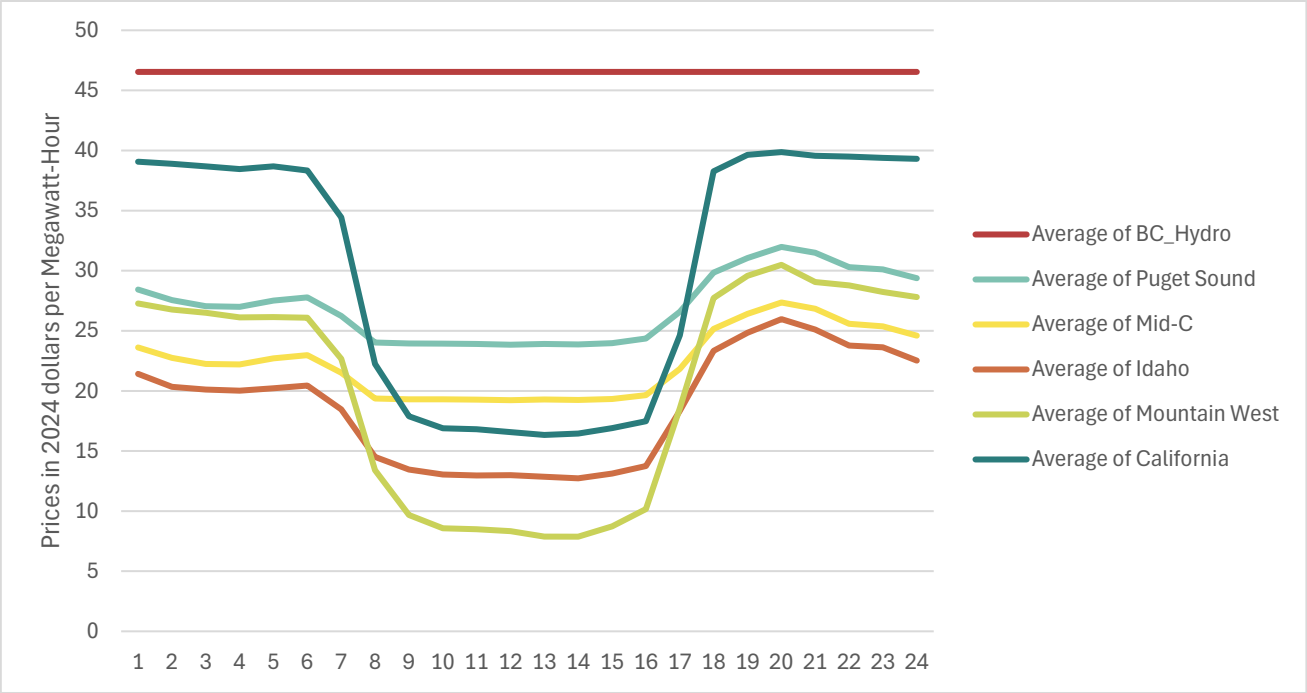
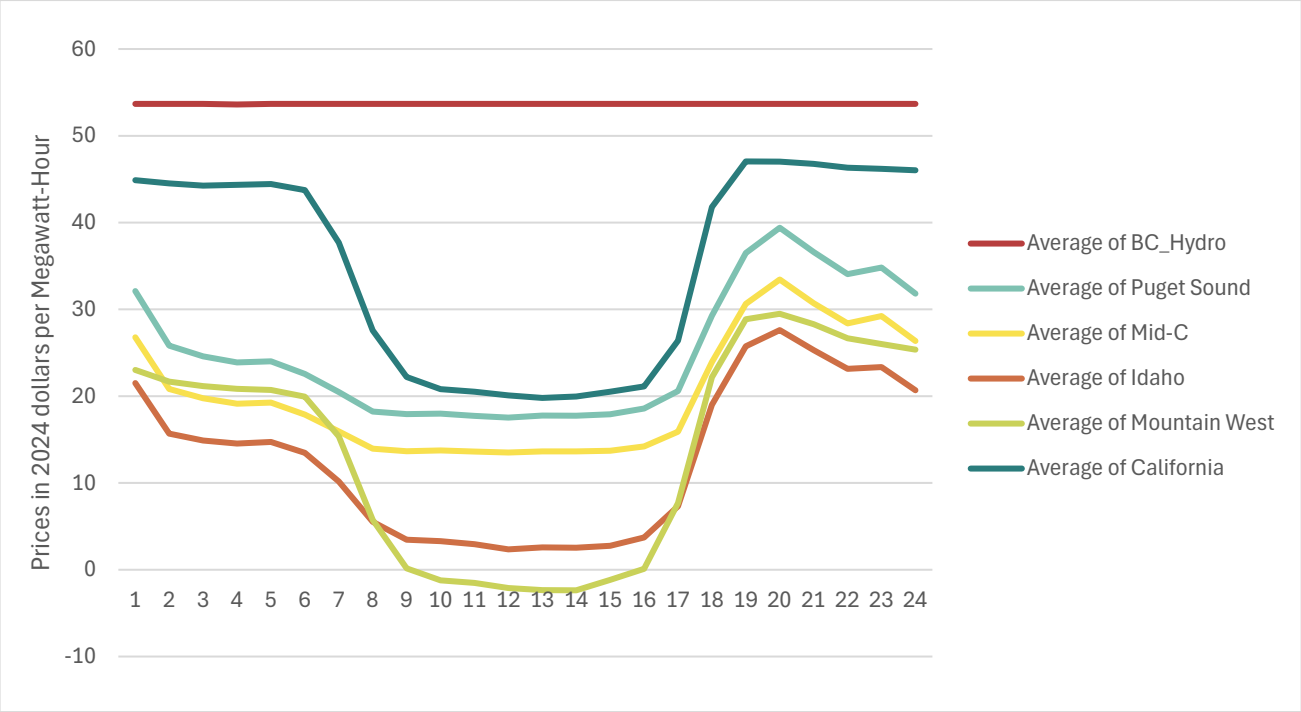


Figure N - 44: Spring Prices in 2046



Spring prices morning and midday go down over time except for Canada and California. During non-evening and nighttime hours prices go slightly up as seen in Figure N - 43 and Figure N - 44. These lower prices make market imports more attractive than most new resources in the spring.

Market prices on the eastside of the region and in the Mountain West are generally lower than the westside of the region and trading partners like California and BC. While prices increase over time, they get lower midday, especially in the spring. New resources that are available during the evening and to a lesser extent the early morning can get more value in deferring market purchases.

Emissions

The Pacific Northwest regional emissions are not direct outputs from the scenario modeling for the Regional Resource Optimization through OptGen/SDDP, as it models the broader WECC. However, they can be estimated from direct outputs of various resource and market utilization results.

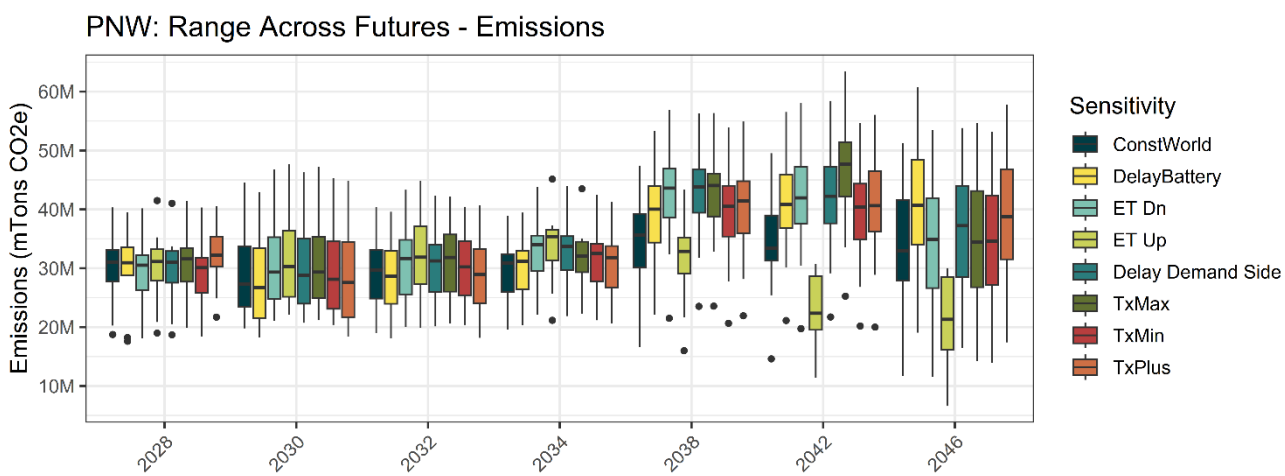
To estimate the emissions for the Pacific Northwest, Council staff aggregated the emissions associated with in-region thermal generation and the emissions associated with net market imports.[18]

[18] To account for 'pass-through' energy or energy transmitted through the Pacific Northwest region but serving load in the broader WECC or Canada, Staff chose to count net imports towards the emissions accounting. Additionally, not all market imports are assumed to be emitting resources. Rather net imports are weighted in alignment with carbon pricing assumptions for the percentage of emitting resources to total generating resources. This aligns our post-modeling

In-region thermal generation emissions are the sum of each thermal plant's generation multiplied by that plant's specific heat rate multiplied by the respective emissions factors for that plant's primary fuel type. The emissions associated with market imports are the net imports to serve PNW load multiplied by the percentage assumption of generation that is emitting multiplied by the heat rate for a combined cycle natural gas plant multiplied by the emissions factor assumption for natural gas. [19] For a more in-depth explanation on the Council's environmental and emissions-related assumptions please refer to both Technical Appendix B – Existing System Parameters and Policies and Technical Appendix C - Methodology for Quantifiable Environmental Costs and Benefits.

Council staff estimated total emissions across both scenarios and all respective sensitivities discussed above. Figure N - 45 shows the distribution of emissions across 10 futures for each of the New Resource and Transmission sensitivities for years modeled in the forecast. Similarly, Figure N - 46 shows the same for the Changing Hydro Operations sensitivities.

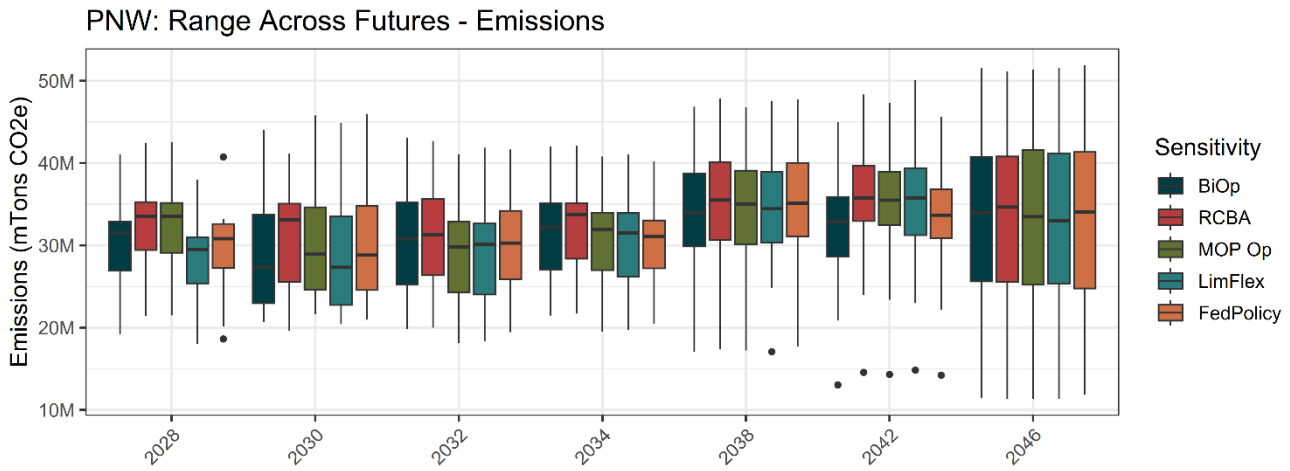
Figure N - 45: Northwest Emissions, Resource and Transmission Risk Sensitivities



emissions accounting with our pre-modeling carbon pricing assumption inputs into OptGen/SDDP. Lastly, net imports do account for line losses to ensure fair comparison with in-region generation.

[19] To calculate the emissions associated with market imports, Council had to impose an assumption on what the marginal emitting generation resource would be and conservatively selected a combined cycle natural gas plant.

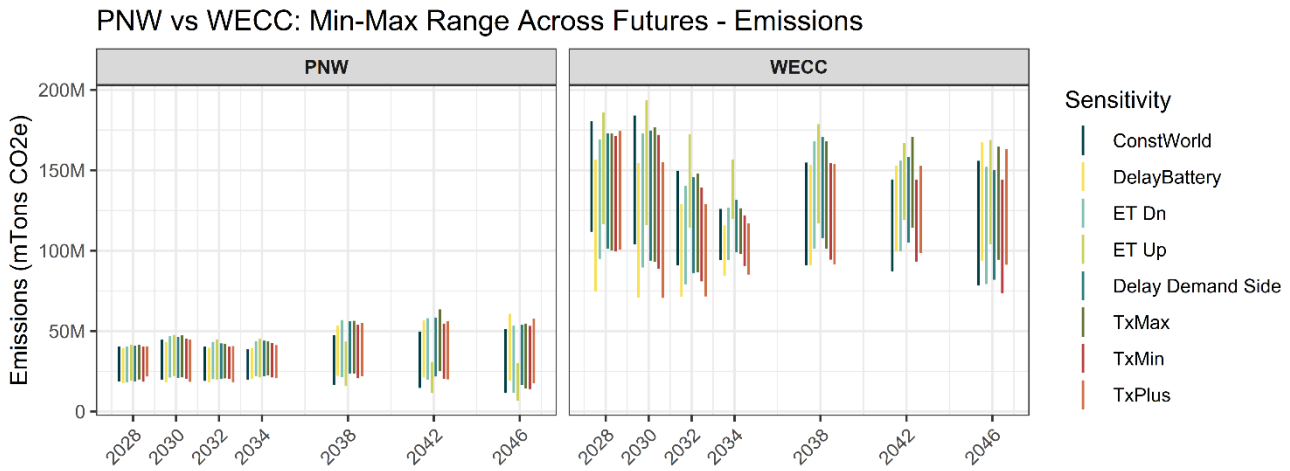
Figure N - 46: Northwest Emissions, Changing Hydro Operations Sensitivities



As can be seen in both plots, the Pacific Northwest emissions are sensitive to the demand pathway, hydro availability, and gas price future the model sees. This is driven largely by how in-region thermal plants are utilized (for generation vs reserves) and market reliance to meet in-region demand giving them wide-ranging distributions which grow in the outer forecast years as the demand distribution (difference in the Low Growth pathway to the High Growth pathway) widens.

Additionally, differences across the sensitivities begin to increase more in the outer years as the resource acquisition paths diverge. The clearest example of this is in the New Resource and Transmission sensitivity where emerging tech costs are assumed to increase (ET Up). In the market availability study for this sensitivity the market buildout was larger in the Pacific Northwest resulting in significantly more renewables and fewer natural gas plants within the region. This in turn lowered the median in-region emissions respective to other sensitivities in the outer years of the forecast range. However, Figure N - 47 highlights the complexity of the interplay between geographical boundaries and global emissions. While the large renewable build within the Pacific Northwest helps meet in-region and WECC-wide policy goals and significantly reduces in-region emissions, it does not change the broader WECC emissions similarly, relative to other sensitivities.

Figure N - 47: Northwest and West-Wide Emissions



In general, all three (Figure N - 45 to Figure N - 47) tell a similar emissions story: emissions are sensitive to the unique combination of demand, hydro availability, and gas prices which directly affect the in-region thermal utilization (both new and existing) and market reliance within the region. Lastly, despite significant load growth across all load pathways, the emissions in the Pacific Northwest and WECC-wide remain relatively flat throughout the forecast period. [20]

For further discussion on greenhouse gas emissions from generation and for historical context please refer to Technical Appendix B – Existing System Parameters and Policies.

Additional Sensitivities

Data Center Sensitivity

Following discussion of initial results at the April 2026 Council meeting, Council members asked staff to run additional analysis to provide context on what resources are being selected to support data center loads. Staff conducted two studies that approach the question from different angles.

The first adjusted the planning reserve margin to account for loads based on some of the lower trajectories. This approach tests what the region would build if some new data centers and chip fabrications were responsible for their own resource adequacy. The load growth from this sector stays in the model, but the adequacy reserve margins are reduced.

The second approach tests what the region would build if tech loads did not show up as forecasted. In this approach, staff removed the load trajectories with the highest forecasted data center growth from

[20] For discussion on the 5 load pathways and load growth over the forecast period, see Technical Appendix F – Electricity Demand Forecast.

the range of futures (this removes the high and early growth pathways). In addition to lowering loads, this approach changes the general supply and demand economics in the model.

Table N - 10 summarizes the overall buildout by 2032 for these two studies as compared to the Transmission Plus sensitivity (used here as a baseline). The largest differences are seen in storage resources, with decreased acquisitions of hybrid renewable and stand-alone storage. Note that while stand-alone renewables increase in sensitivity 2, the increase is offset by the decline in hybrid renewables.

Table N - 10: Data Center Sensitivities

Resource	Transmission Plus	1 – Less DC Adequacy	2 – Less DC Load
Conservation (aMW)	678	555	626
Demand Response (MW)	228	228	224
Voltage Regulation (MW)	222	222	222
Natural Gas (MW)	2,917	2,917	2,850
Wind and Solar (MW)	5,314	5,202	6,780
Hybrid (MW)	2,158	1,110	17
Storage (MW)	2,245	806	0
Long Duration Storage (MW)	20	0	0

Hydrogen and Centralia Modeling Correction

After running the initial full sets of modeling runs, Council staff found two notable errors in the capital expansion model (OptGen).

1) Only the low growth trajectory for hydrogen/industrial decarbonization load was used in the modeling. This was due to a software issue that caused the model to only use data from the low forecast pathway. The impact on the model was largely economic, since hydrogen load is elastic (curtailable at high power prices), and many model build decisions are driven by adequacy and policy needs. Hydrogen loads were modeled correctly in other elements of the Power Plan (including the resource adequacy check).
2) The coal unit Centralia 2 was left active in OptGen throughout the modeling runs, as well as also being modeled as a coal-to-gas conversion. The error likely occurred when staff were trying different approaches to modeling the coal-to-gas conversion at Centralia 2. While available for economic dispatch, the inclusion of the unit does not impact resource adequacy

since it was modeled correctly (removed) in the needs assessment. It was also modeled as a single unit in the market availability study (the coal-to-gas conversion was also not included in the market availability study, given the information available at the time). As a result, like the hydrogen error, this issue was largely economic.

To test the impact of these errors Council staff ran three modeling sensitivities, using Transmission Plus as the baseline for comparison. The results are shown in Table N - 11. Based on the similarity of these results, and discussion with the System Analysis Advisory Committee, Council staff concluded that there was not a need to further re-run the model, and that the original modeling results were sufficient for providing information to the Council for Ninth Plan resource selection.

Table N - 11: Model Correction Runs, Year 2032

Resource	Transmission Plus	1 – Centralia 2 corrected	2 – Hydrogen corrected	3- Both corrected
Conservation (aMW)	678	672	663	663
Demand Response (MW)	228	223	224	224
Voltage Regulation (MW)	222	222	222	222
Natural Gas (MW)	2,917	2,917	3,017	2,917
Wind and Solar (MW)	5,314	5,510	5,317	5,521
Hybrid (MW)	2,158	2,050	2,050	2,050
Storage (MW)	2,245	2,245	2,245	2,245
Long Duration store. (MW)	20	13	0	32

Adequacy Check of Proposed Resource Strategy

The process to develop the resource strategy requires a combination of understanding the buildouts to meet each tested sensitivity and inferring what strategy would satisfy future uncertainties while accounting for considerations and feedback from stakeholders. Once a strategy is developed, it needs to be tested in GENESYS, the Council's resource adequacy model, to determine if the adequacy criteria are all met. Testing the resource strategy is generally a similar process to conducting a needs assessment as described in Technical Appendix M – Needs Assessment Results, but with three main differences. First, the resource strategy is incorporated into the model, unlike the needs assessment that only includes the existing system and therefore evaluating a gap (resource need) in a future year. Second, while the needs assessment was conducted on the high load growth trajectory, the adequacy check considers all load trajectories. Third, the adequacy check only asks whether the region is adequate in 2031 with the resource strategy and is not looking at planning reserve margins and firm energy requirements. If the adequacy criteria is satisfied – meaning all metrics are within their thresholds – then the resource strategy is deemed adequate.

Methodology for Checking Strategy Adequacy

The adequacy check considers all load trajectories, which is an important feature of ensuring adequacy. Typically, as is the case with the needs assessment studies or adequacy assessments, a study that represents a buildout (whether just the existing system or the existing system plus additional resources) and load trajectory is evaluated as a standalone case with its own adequacy results. However, as a resource strategy in a power plan must be robust to account for future uncertainties, including load trajectories, a different nuance is necessary.

Instead of evaluating adequacy under each load trajectory future, the adequacy results of all load trajectories are combined, and the adequacy criteria are evaluated based on the full probabilistic range of uncertainties. This is significant – the question is no longer "is the region adequate in 2031 with the resource strategy under a specific load trajectory?" but rather "is the region adequate in 2031 under the range of load uncertainty?" The quantitative meaning of this philosophical difference can be seen in Table N - 12 shows how the adequacy metric calculations are influenced when adequacy is determined as part of a full distribution of five load trajectories, where calculations are no longer based on 90 years per study, but rather out of 450 years (90 for each load trajectory).

Table N - 12: Changes to Metric Calculations When Considering Full Distribution

Metric & Threshold	0.2	0.1	0.1	8 Hour	1,200 MW	9,600 MWh
	Annual LOLEV	Winter LOLEV	Summer LOLEV	Duration VaR	Peak VaR	Energy VaR
Standalone Study (one load trajectory)	no more than 18 events	no more than 9 events	no more than 9 events	out of 90 simulations		
Full Distribution (five load trajectories)	no more than 90 events	no more than 45 events	no more than 45 events	out of 450 simulations		

Though adequacy is considered on the full distribution of results, each trajectory is simulated independently in GENESYS. Then, all the shortfall records from each study (90 years) are combined into an aggregate 450-year shortfall record. The adequacy metrics are then calculated based on the full distribution of results. If all metrics are satisfied, the strategy is adequate.

Technical Appendix M includes important reminders about the existing system and data assumptions in GENESYS. One emphasis here is the role of market reliance, where the region hedges against over-relying on out-of-region market imports in winter and summer. The Council's market reliance limit is 2,500 MW in winter and 1,250 MW in summer, which was developed with the Resource Adequacy Advisory Committee many years ago. Future work will be conducted on re-evaluating these limits and how new limits would influence the Council's multi-metric adequacy criteria thresholds.

Lastly, as described in Technical Appendix M, sometimes GENESYS computation reaches an infeasibility, and no value is recorded until the computation reaches another stage or seam where it can reach a solution. Staff developed a methodology to replicate any missing values based on

previous days, but it is also possible that an infeasibility occurs during a shortfall. Staff developed another methodology to identify whether these shortfall-infeasibility situations are a model artifact associated with the infeasibility and not "real simulated shortfalls." For a shortfall to be considered an infeasibility artifact it must: (1) experience an infeasibility after first hour, i.e. the shortfall event doesn't end, but rather terminates "mid-event," (2) the thermal system behaves in an unexpected/unrealistic operation during the first hour of the event, such as a sharp drop or below minimum generation, and (3) the region is exporting during the deficit. If these conditions are present, then the shortfall is considered an infeasibility artifact and does not get included in the shortfall record.

The Tested Hydro Conditions

The adequacy check for the Ninth Power Plan includes two different hydro operation regimes: those described in the 2026 Columbia River Basin Fish and Wildlife Program, and those described in the preliminary injunction issued by the federal district court in Oregon in March 2026. The adequacy check will test the resource strategy under both regimes; each tested under the five load trajectories. For a complete list of operations under each regime, see the 2026 Fish and Wildlife Program[21] and the Amended Preliminary Injunction Order.[22]

The following sections are not meant to be detailed summaries, but rather highlight some high-level operations, and there's an important reminder that GENESYS cannot model adaptive management practices – i.e. are no dynamic changes to spill obligation that could occur due to fish count or temperature control, and the model operates given specific operational dates.

2026 Fish and Wildlife Program

The Council's 2026 Fish and Wildlife Program calls for a wide range of measures. As described in Technical Appendix M – Need Assessment Results, several hydro conditions were tested during the needs assessment to help inform the Program and Power Plan.[23] The various operations related to the spill and reservoir operation of the four Lower Snake projects (Lower Granite, Little Goose, Lower Monumental, and Ice Harbor) and the four Lower Columbia projects (McNary, John Day, the Dalles, and Bonneville).

The Program adopted spill measures based on the operations as defined in the 2023 Resilient Columbia Basin Agreement, but without a specific end date to the August performance spill. For spring, this means 24 hour 125% total dissolved gas (TDS) spill. For summer, since the 2026 Fish and Wildlife Program does not include a measure on summer spill, the Council assumed extended

[21] https://www.nwcouncil.org/fs/19912/2026-1.pdf.
[22] *National Wildlife Federation v. National Marine Fisheries Service*, Case No. 3:01-cv-640, Amended Preliminary Injunction Opinion and Order (D. Or. March 2, 2026) https://public.crohms.org/tmt/2674_Amended-PI-Order.pdf.
[23] See Technical Appendix M – Needs Assessment Results.

performance spill until August 31 at the associated Lower Snake and Lower Columbia projects, because this is a more conservative approach for testing power system adequacy.

In addition, the Council's Fish and Wildlife Program calls on operators to limit the flexibility (daily ramping) of the Lower Columbia and Lower Snake projects during the migration season of April-August to minimize the impact on migratory fish populations. [24] The reduced flexibility during this period is as described in the Resource and Transmission Risk scenario.

Preliminary Injunction

The operations described in the Preliminary Injunction (PI) focus on the Lower Columbia and Lower Snake projects. High-level, they call for spring spill of 24-hour 125% TDG and expended summer performance spill until August 31, including at John Day. These operations also call for some changes to winter and fall spill of continuous 24-hour surface weir spill instead of only 4 hours in the mornings in the March 1-20 and September 1-November 15 time frames. The injunction does not change pool elevation operations from the 2020 Biological Opinion, nor does it specifically call for limiting flexibility of the Lower Snake and Lower Columbia projects during the spring and summer.

Adequacy Check Results

The adequacy check of the 2026 Fish and Wildlife Program shows the region will be adequate in 2031 with the Ninth Plan resource strategy. Seen in Table N - 13, all adequacy metrics in the criteria are met when considering the full load trajectory distribution. While this is the main takeaway, Table N - 14 shows the adequacy metrics when considering the load trajectories separately. While the strategy is adequate on the full distribution, the high growth trajectory does exhibit metrics that are violated, suggesting that the resource strategy is not built just to meet adequacy under the highest loads.

Table N - 13: Adequacy Results of Full Trajectory Distribution

Metric	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
2026 F&W Program	0.068	0.053	0.006	1.8	582	1,452
Court Ordered PI	0.073	0.067	0.007	2.5	579	579

[24] See Technical Appendix M – Needs Assessment Results and 2026 Columbia Basin Fish and Wildlife Program.

Table N - 14: 2026 Fish and Wildlife Program Adequacy Results of Individual Trajectories

Metric	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
High Growth	0.233	0.2	0.02	7.5	2,835	11,312
Late Growth	0.067	0.067	0	0	0	0
Early Growth	0.022	0	0	0	0	0
Mixed Bag	0.011	0	0.01	0	0	0
Low Growth	0.011	0	0	0	0	0

When evaluating the adequacy metrics, it is important to keep in mind the significance of each metric and the interpretation of the value. For frequency metrics of LOLEV, a value of 0 means that no simulated events took place during the relevant period of the metric. For example, in the table above, the resource strategy resulted with no winter events under the Early Growth, Mixed Bag, and Low Growth load trajectories. This means that in 10 years, the resource strategy (in these load trajectories) would not expect to have a winter event. To find the number of simulated events under the standalone load trajectories, either annual or seasonal, each value can be multiplied by 90 (the number of simulation years by trajectory) and rounded up. For example, under the High Growth study, there were 21 total events with 18 in winter and 2 in summer (this annual and winter result violates the criteria).

Interpreting the extreme deficit VaR metrics is a little different. Here, the metric represents the 97.5th value of a distribution, either duration, peak magnitude or energy. Unlike 0 in the LOLEV metric that means no events occurred, a zero value for a VaR metric only means that the 97.5th percentile value is zero and it is possible that higher percentile values have non-zero deficits (as long as events occurred). In other words, as long as the annual LOLEV is non-zero, it means events occurred in at least one simulation. For example, the Mixed Bag trajectory only had one event (Annual LOLEV of 0.011* 90 simulation = 1) in the summer. Because only one simulation had an event, out of 90, it means that the 97.5th percentile of a distribution of 1 simulation with a deficit and 89 simulations without deficits, is zero. However, in the High Growth trajectory, the 97.5th percentile of Peak is 2,835 MW, which means that in 39 out of 40 years, the region would be expected to experience peak events up to 2,835 MW, exceeding the 1,200 MW threshold.

The adequacy check for the Court ordered Preliminary Injunction also shows the region will be adequate in 2031, as seen in Table N - 13 showing the results across the full range of load trajectories. One key difference between the two sets of operations is the amount of assumed flexibility in the system. As the Preliminary Injunction does not specifically limit daily ramping, the Council's GENESYS model sees potential to ramp the existing system during the spring and summer (while continuing to meet all other requirements for hydro operations). Analysis has shown this flexibility can improve the adequacy of the system when allowed and under certain conditions.

Similar to the check against the 2026 Fish and Wildlife Program, while the strategy is adequate when considering the full range of load uncertainty, not all individual trajectories are adequate by themselves (see Table N - 15). This further emphasizes that the strategy is not only tuned for high demand growth. While there are some differences in adequacy signals in standalone load trajectories, what matters is that both regimes satisfy the Council's adequacy criteria when considering the full load trajectories. Individual operations may vary due to the influence of limiting or not limiting flexibility, which (1) may result in seasonal operational changes and (2) how the system responds to stressful conditions.

Table N - 15: Preliminary Injunction Adequacy Results of Individual Trajectories

Metric	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
High Growth	0.011	0.011	0	0	0	0
Late Growth	0.189	0.189	0	18.8	3,458	34,578
Early Growth	0.133	0.133	0	4.5	2,248	9,239
Mixed Bag	0.033	0	0.033	0	0	0
Low Growth	0	0	0	0	0	0

Technical Appendix O: Cost-Effective Conservation Methodology and Results

Contents

Introduction 1
Method for Determining the Cost-Effectiveness Limit for Conservation 2
Conservation Avoided Cost Components 4
Cost-Effective Conservation Results 8
Residential Sector Results 10
Commercial Sector Results 11
Industrial Sector Results 13
Agricultural Sector Results 15
Distribution System Results 16

Introduction

The methodology and input parameters defined in this section are used to calculate conservation measure cost-effectiveness relative to the findings of the Ninth Power Plan.[1] The resource strategy (see Chapters 4 and 5) determines the overall conservation target amount and avoided cost. The targets are then used to define the remaining avoided cost components for use in evaluating measure cost-effectiveness. Background material on developing the conservation measures, the supply curves, and most of the cost and benefit components can be found in Technical Appendix H – Conservation Methodology and Potential.

[1] This methodology was developed to reflect the proposed dual target approach to conservation, as proposed in the draft Ninth Power Plan. The topic of a dual versus single target for conservation is an area of ongoing discussion during the public comment process. Should the Council shift towards a single target in the final Power Plan, the methodology will be updated to reflect regional values, as needed.

Method for Determining the Cost-Effectiveness Limit for Conservation

The conservation targets represent the conservation resources needed to meet the Ninth Plan requirement for an adequate, efficient, economical, and reliable power system. The resource strategy and conservation targets are established through optimization modeling that compares both generating and demand-side resources (e.g., conservation, demand response, etc.) against the Northwest's power system needs. The modeling results and interpretation of those results determine the conservation targets consisting of amounts of energy (average megawatts, or aMW) and their associated levelized cost bins. From these target amounts, the specific components of the avoided costs are determined. The avoided costs represent the value of the next available combination of resources from which the target was derived. In this way, the cost-effectiveness for conservation measures is always measured relative to the plan findings. The avoided cost can then be used going forward to calculate benefit cost ratios for new or updated measures.

As conservation measures are reviewed and updated, conservation program managers, the Regional Technical Forum (RTF), and regulators should use the benefit/cost ratio method outlined below to determine cost-effectiveness for measures relative to the Ninth Plan. The RTF will provide clear guidance on cost effectiveness at the measure application level following this methodology and these parameters for the measures it maintains. These should be adopted by Bonneville to meet its cost-effective conservation resource obligations as outlined in Chapter 5.

This method assures that all the costs and benefits are captured, that the time-dependent shape of the savings is accounted for, and that the capacity contribution of the measures is fully considered. This method is also consistent with the approach outlined in the Methodology for Quantifiable Environmental Costs and Benefits appendix (see Technical Appendix C). Individual entities may have differing input values than the ones presented below, given specific needs, but the methodology to estimate these parameters should be consistent. If a measure's benefit-to-cost ratio from this perspective is one or greater, the measure is considered cost-effective relative to the alternative resources defined in the Plan. This ratio is calculated as follows, where all parameters are in constant dollar value:

$$\text{Benefit Cost Ratio} = \frac{\text{NPV(energy + capacity + annual O\&M}_{\text{avoided}}\text{ + other fuel + NEI)}}{\text{NPV(capital cost * (1 + admin) + annual O\&M + other fuel + NEI)}}$$

where NPV is the net present value and

$$\text{energy} = \text{kWh}_{i,bb} * ((\text{MP} + \text{CO2}_{\text{avoided}})_i + \text{RMC}) * (1 + \text{RAC})$$

$$\text{capacity} = \text{kW}_{\text{peak},bb} * (\text{T}_{\text{avoided}} + \text{D}_{\text{avoided}} + \text{R}_{\text{avoided}}) * (1 + \text{RAC})$$

For the energy and capacity formulas above, *i* represents the time segment (e.g., heavy/light load hours, monthly) and *bb* represents busbar. Loss factors of 2.8% for transmission (T) and 4.4% for

distribution (D) are included for calculating busbar savings (See Technical Appendix A – Global Assumptions). Note that these values are average losses on the system and are used as inputs to calculate cost effectiveness using the Council's conservation cost-effectiveness calculator, ProCost. However, ProCost uses these values to calculate the marginal line losses[2], which can be much significantly than the average.

The inputs in the benefit cost ratio formula are further defined in Table O - 1 below. In addition to term definitions, the table also outlines whether the inputs are benefits and/or costs, and where the specific values are derived.

Table O - 1: Summary of inputs in the Council's benefit cost calculation for conservation

Term	Definition	Benefit?	Cost?	Value
Capital cost	Incremental measure cost ($) (includes equipment and labor)		X	Measure specific
Admin	Program administration cost adder		X	Varies by sector
Annual O&M	Operations and maintenance costs ($/year)	X	X	Measure specific
NEI	Non-energy impacts ($)	X	X	Measure specific
Other fuel	Non-electric (e.g., natural gas use) impacts ($)	X	X	Measure specific
kWh	Energy saved (in kWh)	X		Measure specific
MP	Market price, from Ninth Plan forecast ($/MWh)	X		Forecast file
RMC	Risk mitigation credit ($/kWh)	X		W: $0.070/kWh E: $0.025/kWh*
kW_{peak}	Power saved during peak periods (kW)	X		Measure specific
$CO2_{avoided}$	Value of avoided carbon ($/MWh)	x		Forecast file
$T_{avoided}$	Deferred transmission capacity credit ($/kW-yr)	X		W: $14.69, E: $4.77*
$D_{avoided}$	Deferred distribution capacity credit ($/kW-yr)	X		W: $24.18, E: $11.71*

[2] Marginal line losses are the line losses incurred by an incremental increase in line loading. Conservation reduces line loading at the margin and therefore avoids these marginal line losses. The Council and RTF have developed a method for calculating time-varying, marginal T&D (line) losses which is used for calculating site-to-busbar impacts for conservation measures. Marginal line losses are independent of core ("iron") line losses and are greater than average resistive line losses. The full methodology can be found in the presentation titled "T&D Losses and Calculations for Energy Efficiency".

Term	Definition	Benefit?	Cost?	Value
$R_{avoided}$	Deferred resource capacity credit ($/kW-yr)	X		$77
RAC	Regional act credit for conservation	X		10%

"Measure Specific" means that the value, if applicable, is unique to each measure
"Forecast File" means that the values for this attribute can be found in the MC_and_Loadshape file.
* Different values for the western (Oregon and Washington) and eastern (Idaho and Montana) parts of the region.

Many of these parameters are included as inputs in the net levelized cost of energy for the conservation supply curves used in the portfolio analysis (See Technical Appendix H). However, several of the parameters are developed based on the results of the plan, including the risk mitigation credit and the deferred resource capacity credit. In addition, a revised market price forecast is produced based on the results of the plan.

Conservation Avoided Cost Components

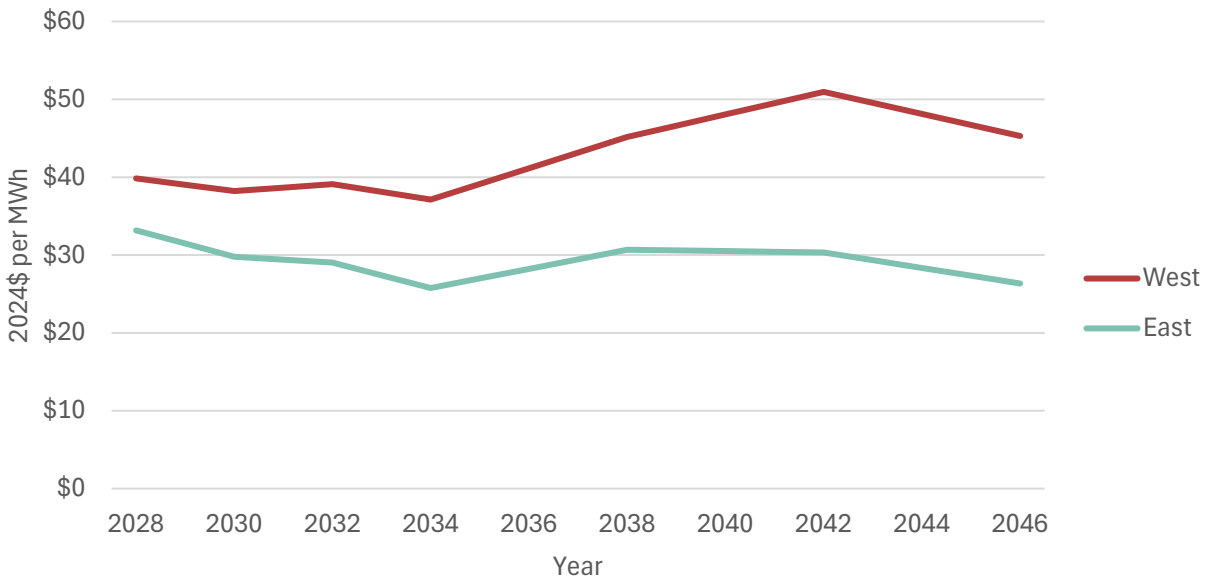
The primary components of the avoided costs of conservation include the market price forecast (MPF), the risk mitigation credit (RMC), the deferred resource capacity credit (DRCC), and the deferred transmission and distribution credits. For the Ninth Plan, these values also differ based on location, so there are two values, or sets of values for each parameter, except for the DRCC. In addition, for the West part of the region, a value for avoided carbon is included.

Market Price Forecast - Value of Avoided Energy

Even though the measure energy savings are known, the total dollar value of these energy benefits is unknown *a priori*; it is determined through the portfolio model findings. The MPF is derived from the resource strategy using the OptGen model. The MPF combined with the conservation savings represents the avoided cost of energy for a given measure. The average market prices of electricity are shown in Figure O - 1.

The figure shows separate MPF estimates for the West side of the region, defined as Oregon and Washington, and the East side, defined as Idaho and Montana. The Council decided to use separate MPF estimates as these were shown to be significantly different.

Figure O - 1: Annual Average Electricity Market Prices from OptGen



Deferred Resource Capacity Credit

The DRCC was a key factor in the 2021 Power Plan (8th Plan), as the models exhibited a high value for conservation during the shoulder hours of each day – just before sunrise and just after sunset. These were considered the "hours of greatest need" when the market prices of electricity were at their highest. The Ninth Power Plan analysis shows a much stronger need for energy at all hours but also shows value for conservation occurring during key hours. The DRCC was developed for the Ninth Plan based on the cost of a simple cycle combustion turbine (SCCT) of $122/kW-yr. The method of calculating the value associated with the annual deferment of the generation implies that the resource purchase is deferred until the end of its life. That means the cost of investing in the resource is temporarily saved. The cost savings are the cost of investing now versus the cost of investing later, which ends up being the difference in the discounted cost stream of the investment over time. The resulting value of $77/kW-yr represents this value of deferring the resource build rather than avoiding it altogether.

The hours where this credit applies is also an input to ProCost. For winter, the hours ending 8, 9, 18, and 19, and for summer hours ending 17, 18, 19, and 20 represent the hours for the DRCC.

Transmission and Distribution System Deferral Credit

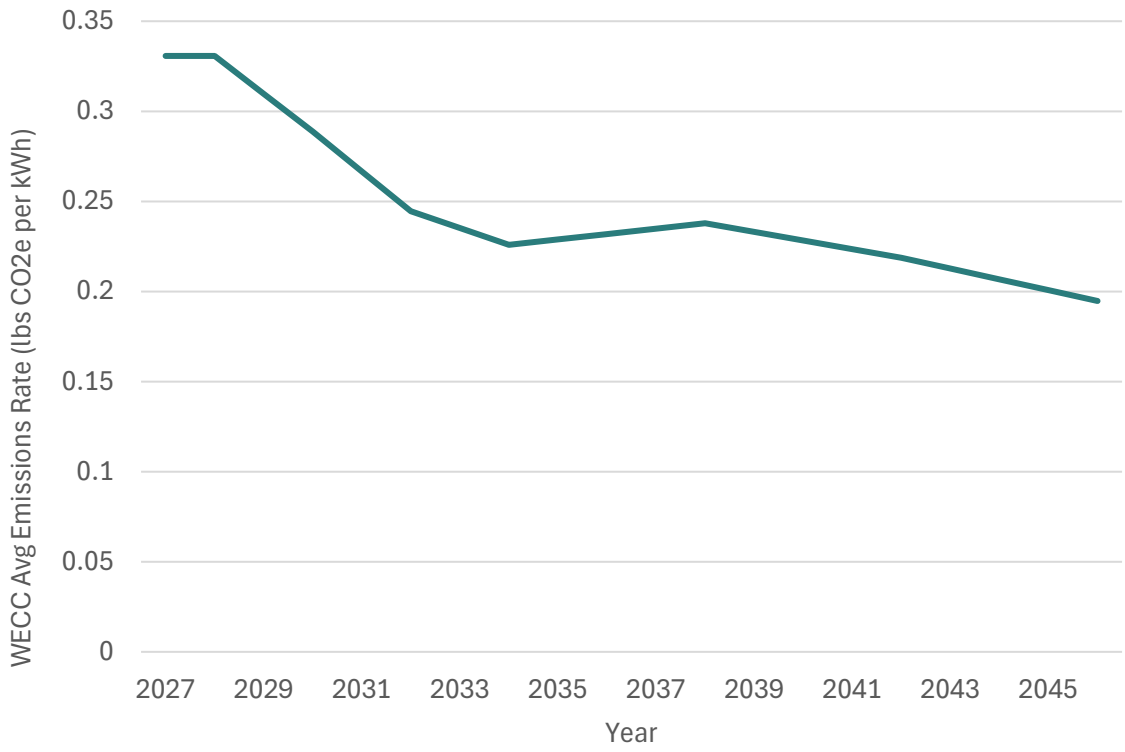
As indicated in Table O - 1, the deferred transmission capacity credit values are $14.69/kW-yr for the West and $4.77/kW-yr for the East portion of the region. The deferred distribution system capacity credit values are $24.18/kW-yr for the West and $11.71/kW-yr for the East. See Technical Appendix A – Global Assumptions for more information on these values.

Value of Avoided Carbon

As discussed in Technical Appendix B – Existing System Parameters and Policies, both Washington and Oregon have policies aimed at decarbonization. This includes the Clean Energy Transformation Act and Climate Commitment Act in Washington, as well as the Clean Energy Targets Bill in Oregon. These policies either directly or indirectly place a high value on avoiding the production of carbon dioxide.

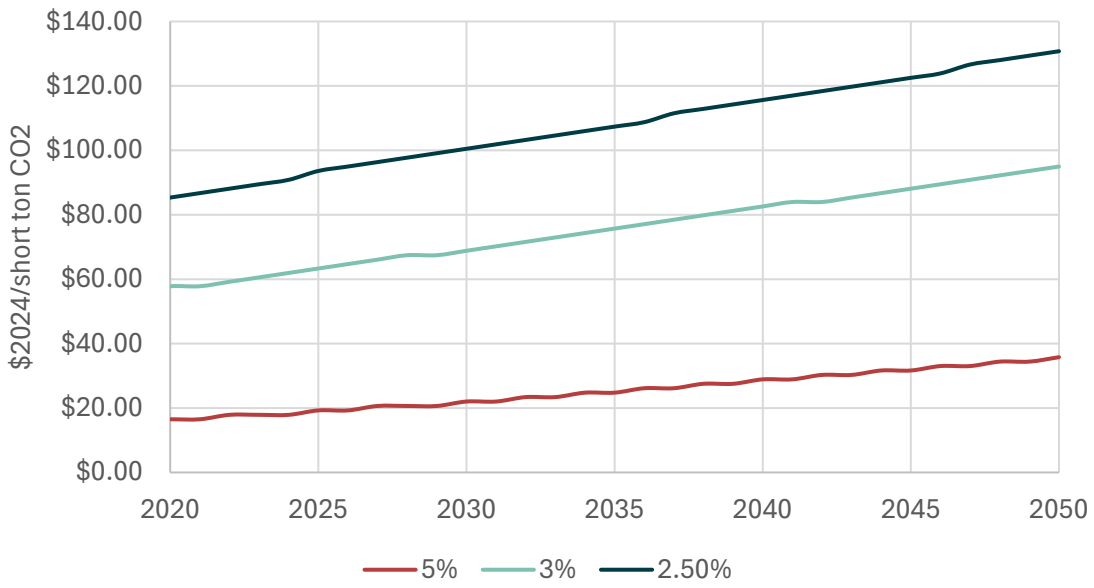
For this reason, the avoided cost of carbon is included in the cost effectiveness framework, but only for the West modeling zones in Oregon and Washington. An avoided cost of carbon for conservation requires two elements: the marginal CO2 emissions rate (lbs/kWh) the conservation is avoiding, and the price ($/lb, or $/ton) of the avoided carbon. Figure O - 2 shows the first element – the estimated marginal CO2 emissions rate. For simplicity, the Council used the overall WECC modeled emissions rate as a proxy of the marginal Northwest emissions rate, as a market purchase is often on the margin.

Figure O - 2: Marginal Carbon Dioxide Emission Rates (lbs/kWh)



For the carbon prices, the Council used the Social Cost of Carbon with the three percent discount rate (see Figure O - 3).[3] These prices, along with the avoided emission rates, were applied to the West portion of the region.

Figure O - 3: Social Cost of CO2 (SC-CO2): 2020 - 2050 (Short Tons)



Risk Mitigation Credit

The RMC is the value of efficiency to avoid a variety of risks. Because the Council assesses a wide range of futures (varying loads, hydro conditions, renewable profiles, temperatures) and multiple scenario analyses, the Council uses the risk mitigation parameter to approximate the value of conservation in reducing risk across all the future unknowns. The Ninth Power Plan clearly indicated that when the system is constrained, the value of conservation increases. The risk mitigation parameter is then estimated to define that added value of conservation. The process for determining this credit value involved the following steps:

1) Calculate the benefit cost ratios (BCRs) of all conservation measures using the above parameters (including the MPF) except the RMC.
2) Sum all the potential for measures with BCRs greater than or equal to 1.0 and compare that potential to the target.
3) If the total is less than the target, then estimate the amount of extra RMC value needed to reach the target.

[3] https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

4) Rerun ProCost with this new RMC value and check the total potential with BCRs ≥ 1.0.
5) Repeat steps 3 and 4 until the new total equals the targets.

For the Ninth Power Plan, the Council found that RMC values of $70 per megawatt-hour ($0.070 per kilowatt-hour) for Washington and Oregon, and $25/MWh ($0.025 per kilowatt-hour) for Idaho and Montana are needed to achieve the targets provided in Chapter 5, the Conservation Program.

Multiple iterations were needed to arrive at the final RMC values. The West value in particular required additional iterations, as there are versions of the supply curves that have additional potential available in Oregon and Washington in futures with higher electrification assumed. Since there is more potential available in the higher electrification futures, it would take a lower RMC to meet the target amount of 860 aMW in a high electrification future and a higher RMC to meet the target amount in a lower electrification future. To account for this, the Council selected an RMC value ($70/MWh) that reached approximately 860 aMW on average across the higher and lower electrification futures.

Cost-Effective Conservation Results

The total cost-effective conservation potential in the region is 1,060 aMW by 2032. This value is the result of two separate targets of 860 aMW for Oregon and Washington (West) and 200 aMW for Idaho and Montana (East) (see Chapters 4 and 5). The breakdown of that potential by year, location, and sector is shown in Figure O - 4.|

Figure O - 4: Cost Effective Potential, by Location, Year, and Sector

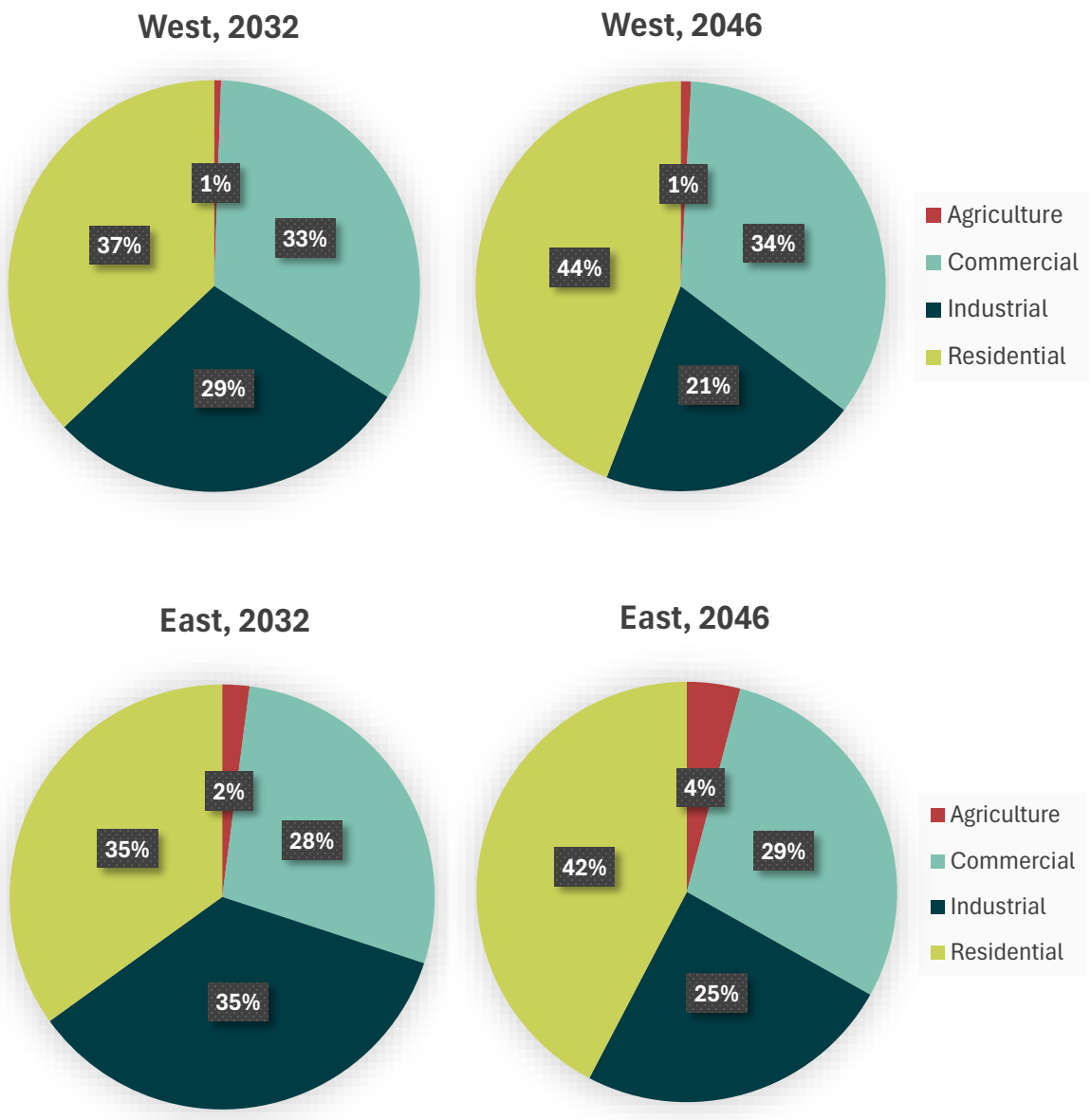


Figure O - 4 exhibits a relatively similar sector breakdown for the East and West parts of the region. For the West, the residential sector shows the largest cost-effective potential (37%) by the end of the Action Plan in 2032, followed by the commercial sector (33%), industrial sector (29%), and agricultural sector (1%). By the end of the Ninth Plan period in 2046, the residential and commercial sector shares grow to 44 and 34% respectively, followed by the industrial sector at 21% and the agricultural sector at 1%.

The East sector breakdown looks relatively similar to the West, with a couple of slight differences. Similar to the West, the East shows the residential sector having the most cost-effective potential by 2046 (42%) and is tied with the industrial sector as having the most potential by 2032 (35%). Unlike

the West, the East shows slightly higher industrial cost-effective potential in 2032 (35%) as compared to commercial (28%); however, this rank order shifts by 2046 with an estimated 29% in commercial and 25% in industrial. Unsurprisingly, the East shows a higher amount of agricultural cost-effective potential than the more urban West, with a 2% share in 2032, growing to a 4% share by 2046.

The following sections break down the sector level results further to explore cost effectiveness at the end use and measure levels.

Residential Sector Results

The residential sector holds the largest cost-effective potential in the region, accounting for nearly 400 aMW by 2032 and growing to nearly 1,600 aMW by 2046.

Table O - 2 shows how the cost-effective residential sector potential breaks down by end use for the West (Oregon and Washington) by 2032 and 2046. By 2032, HVAC is the end use with the largest cost-effective potential (at 38% of the total), followed by water heating (20%), electronics (20%), and dryers (8%). By 2046, water heating grows to the largest end use at 31%, followed by HVAC at 22%, dryers at 20%, and electronics (15%).

Table O - 2: Residential Cost-Effective Potential by End Use, West (OR and WA)

End Use	2032	2046
HVAC	38%	22%
Water Heating	30%	31%
Electronics	20%	15%
Dryer	8%	20%
Refrigeration	3%	4%
Vehicle	2%	8%
Food Preparation	0%	0%
Grand Total	**100%**	**100%**

In 2032, various weatherization measures, including envelope insulation, efficient storm windows, and air sealing make up the majority of HVAC savings (60% of the total), followed by heat pump retro-commissioning and upgrades (27%), and duct sealing (12%). By 2046, the largest HVAC cost-effective savings shift to heat pump retro-commissioning and upgrades (46%), followed by weatherization measures (38%), and duct sealing (11%). For water heating, the vast majority of energy savings (~90%) in both 2032 and 2046 are attributable to heat pump water heaters, with the remainder coming from thermostatic shower restriction valves and efficient portable spas. For electronics, most savings come from efficient TVs (~50%), followed by efficient clothes washers (~30%), and efficient computers.

Similarly, Table O - 3 shows how the cost-effective residential sector potential breaks down by end use for the East (Idaho and Montana) by 2032 and 2046. While the top three end uses categories for the East – water heating, electronics, and HVAC – are the same as those of the West, some differences can be observed. For example, the share of HVAC savings in the East is significantly lower than that of the West; however, water heating and electronics (appliance) savings are higher.

Table O - 3: Residential Cost-Effective Potential by End Use, East (ID and MT)

End Use	2032	2046
Water Heating	31%	36%
Electronics	23%	19%
HVAC	21%	10%
Vehicle	15%	11%
Dryer	8%	22%
Refrigeration	1%	2%
Food Preparation	0%	0%
Grand Total	**100%**	**100%**

In terms of measure savings, the make-up of the underlying measures for the East within end use categories is relatively similar to that of the West. For example, the majority of cost-effective HVAC savings in 2032 is made up by weatherization measures (63%), followed by heat pump retro-commissioning (14%), and duct sealing (21%). Heat pump water heaters significantly dominate water heating cost-effective potential (at approximately 90%), and electronics savings again are predominantly televisions (~40%), clothes washers (~25%), and computers.

Commercial Sector Results

The commercial sector accounts for the next largest cost-effective potential in the region, totaling nearly 350 aMW of potential by 2032 and growing to just over 1,200 aMW of potential by 2046.

Table O - 4 shows how the cost-effective commercial sector potential breaks down by end use for the West by 2032 and 2046. Similar to the residential sector, HVAC represents the end use with the largest cost-effective potential by 2032 (49%) and 2046 (62%). The largest portion of this cost-effective HVAC savings is associated with variable refrigerant systems with very high efficiency dedicated outside air (VRF with VHE DOAS), followed by window upgrades, heat recovery ventilation (HRV), and high efficiency fans. Refrigeration represents the end use with the next largest potential, at least in the nearer term, accounting for 12% of cost-effective savings by 2032 and 7% of savings by 2046. This end use is entirely made up of efficient upgrades to refrigeration equipment in grocery applications. Beyond HVAC and refrigeration, other significant end uses include:

- whole building, primarily representing strategic energy management (SEM);

- electronics, including efficient servers, computers, and televisions;
- lighting, primarily representing the addition of advanced controls;
- water heating, dominated mostly by heat pump water heaters and circulator pumps; and
- vehicles, represented by engine block heater controls.

Table O - 4: Commercial Cost-Effective Potential by End Use, West (OR and WA)

End Use	2032	2046
HVAC	49%	62%
Refrigeration	12%	7%
Whole Building	10%	5%
Electronics	9%	3%
Lighting	9%	8%
Water Heating	4%	5%
Vehicles	4%	3%
Motors/Drives	2%	3%
Food Preparation	1%	2%
Appliances	1%	2%
Compressed Air	0%	1%
Other	0%	0%
Grand Total	**100%**	**100%**

Similarly, Table O - 5 shows how the cost-effective commercial sector potential breaks down by end use for the East by 2032 and 2046. The East end use breakdown is largely similar to the West breakdown, with cost-effective HVAC savings dominating the total, with 45% of the total savings by 2032 and 57% by 2046. The measures underlying these savings are also similar, with VHE-DOAS, windows, and HRV accounting for the top three individual measures. Aside from HVAC, the top end uses for the East side are largely similar to the West, with the next largest end uses being a mix of electronics, whole building, lighting, and refrigeration. Refrigeration savings are not quite as significant in the East (9% versus 12% for the West), but still within the top five end uses. The measures underlying the end use categories are also similar to the West, with some cost-effective applications of SEM, heat pump water heaters, efficient servers and computers, advanced lighting controls, and engine block heater controls.

Table O - 5: Commercial Cost-Effective Potential by End Use, East (ID and MT)

End Use	2032	2046
HVAC	45%	57%
Electronics	12%	5%
Whole Building	10%	5%
Lighting	10%	10%
Refrigeration	9%	5%
Vehicles	7%	5%
Water Heating	3%	4%
Food Preparation	2%	3%
Motors/Drives	2%	3%
Appliances	1%	2%
Other	0%	0%
Compressed Air	0%	0%
Grand Total	**100%**	**100%**

In comparing the differences between the East and West cost-effectiveness, it is often the case that if a given measure category is cost-effective in the West it is also cost-effective in the East; however, the difference is often how many applications of the measure are cost-effective. For example, of the approximately 600 individual applications of VHE-DOAS, about 85% are cost-effective in the West versus about 33% in the East. Therefore, both locations have cost-effective applications of VHE-DOAS, but the West has more applications crossing the cost-effectiveness threshold.

Industrial Sector Results

The sector accounting for the next largest cost-effective potential in the region is the industrial sector, totaling just over 300 aMW by 2032 and growing to nearly 800 aMW by 2046.

Table O - 6 shows how the cost-effective industrial sector potential breaks down by end use for the West by 2032 and 2046. Unlike the residential and commercial sectors, HVAC is not the end use with the largest potential, largely driven by the fact that heating and cooling tends to be a smaller fraction of energy use in industrial facilities than commercial buildings and residences. For industrial, the largest cost-effective savings potential is found in whole building measures, which is predominantly strategic energy management (SEM). SEM, a method of continuously tracking and reducing overall facility energy usage over time, accounts for approximately half of industrial energy savings potential by 2032 and nearly a third by 2046. HVAC accounts for the next largest end use, accounting for about 10% of the cost-effective industrial potential. This potential is made up by more efficient heating via heat pumps and higher efficiency mechanical cooling.

Table O - 6: Industrial Cost-Effective Potential by End Use, West (OR and WA)

End Use	2032	2046
Whole Building	49%	31%
HVAC	10%	7%
Pumps	9%	15%
Compressed Air	9%	12%
Fans and Blowers	7%	11%
Refrigeration	7%	7%
Material Processing	5%	11%
Lighting	3%	4%
Other Motors	1%	1%
Material Handling	0%	1%
Grand Total	**100%**	**100%**

The next highest potential end uses in industrial are generally considered end uses centered around "motors and drives" – pumps, compressed air, and fans are all highly tied to motor and motor system efficiency. Collectively, these motor and drive system measures account for over a third of the total cost-effective potential.

The cost-effective industrial breakdown by end use for the East is show in Table O - 7, and again, the overall distribution is very similar to that of the West. Whole building measures, such as SEM, account for the highest share of savings, by a wide margin, followed by HVAC, motor and drive end uses, and refrigeration. A couple of individual industrial measures are found to be cost-effective in the West but not in the East. These include fast-acting doors in refrigerated warehouses and "industrial heat pumps," or heat pumps used for process loads rather than space conditioning.

Table O - 7: Industrial Cost-Effective Potential by End Use, East (ID and MT)

End Use	2032	2046
Whole Building	55%	38%
HVAC	11%	8%
Pumps	8%	15%
Fans and Blowers	7%	11%
Compressed Air	7%	10%
Refrigeration	6%	7%
Lighting	3%	4%
Material Processing	2%	5%

End Use	2032	2046
Material Handling	0%	1%
Other Motors	0%	0%
Grand Total	**100%**	**100%**

Agricultural Sector Results

The final sector, agriculture, has the smallest savings potential primarily due to its locational nature. While there are homes and business scattered in every corner of the region, the bulk of the agricultural area in the region is located primarily in eastern Oregon/ Washington and Idaho. In total, the Ninth Plan includes about 10 aMW of cost-effective agriculture potential by 2032 and just over 50 aMW of potential by 2046.

The end use breakdown for cost-effective agriculture potential for the West and East parts of the region is shown in Table O - 8 and Table O - 9 below. In both cases, irrigation accounts for the vast majority of energy savings potential, accounting for between 75 and 90% of all savings across the region and over the Plan period. Cost-effective irrigation measures include hardware upgrades for various types of irrigation systems, such as pivots, linear systems, and wheel and hand-lines. Other cost-effective irrigation measures include efficient irrigation pump motor replacements and advanced irrigation management – a suite of tools to optimize crop irrigation levels.

Table O - 8: Agricultural Cost-Effective Potential by End Use, West (OR and WA)

End Use	2032	2046
Irrigation	87%	75%
Lighting	5%	3%
Refrigeration	4%	4%
HVAC	2%	17%
Motors/Drives	1%	1%
Process Loads	1%	1%
Grand Total	**100%**	**100%**

Aside from irrigation, the next largest end uses for savings potential include lighting, refrigeration, motors and drives, and HVAC. Most of the refrigeration, HVAC, and non-irrigation pump motor savings are tied to the dairy industry, including measures for refrigeration heat recovery, variable-speed drives on milk transfer pumps, and more efficient ventilation fans in dairy operations.

Table O - 9: Agricultural Cost-Effective Potential by End Use, East (ID and MT)

End Use	2032	2046
Irrigation	83%	81%
Refrigeration	9%	8%
Motors/Drives	3%	3%
Lighting	3%	1%
HVAC	2%	5%
Process Loads	0%	1%
Grand Total	**100%**	**100%**

Distribution System Results

The distribution system efficiency, specifically conservation voltage reduction (CVR), was modeled differently in the Ninth Plan than in previous plans. The Council developed measures for the conservation supply curves and separately developed a demand response product (demand voltage reduction, or DVR) that was included in the DR supply curve. However, including both CVR and DVR could potentially double-count the same resource; therefore, the Council decided to input the resource only as DVR, and allow it to run whenever the model preferred. This way, the model could choose the optimum mode of operation; either CVR (running all the time) or DVR (running intermittently). While the model generally showed a preference for CVR in the Action Plan period, the Council recognizes that utilities may have their own unique needs, and therefore recommends utilities pursue this resource in whatever form provides the most value for their system (see Chapter 4 – Action Plan for more details).

Technical Appendix P: Model Conservation Standards and Conservation Program Details

Contents

Introduction 1
Model Conservation Standards 2
Model Conservation Standard for Data Centers 2
Model Conservation Standard for Heat Pump Retro-Commissioning 4
Other Conservation Program Details 8
Additional Guidance for Heat Pump Ready Homes 8
Surcharge Recommendation 10
Surcharge Methodology 10
Identification of Customers Subject to Surcharge 10
Calculation of Surcharge 11
Evaluation of Alternatives and Electricity Savings 11

Introduction

The Northwest Power Act directs the Council to adopt and include in its power plan a conservation program that includes model conservation standards (MCS).[1] The MCS are applicable to (i) new and existing structures; (ii) utility, customer, and governmental conservation programs; and (iii) other consumer actions for achieving conservation. The Act requires that the standards reflect geographic and climatic differences within the region and other appropriate considerations. The Act also requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities. In addition to the requirements set forth in

[1] Northwest Power Act, Section 4(f)(1).

the Act, the Council believes the MCS in the plan should produce reliable savings and that the standards should, where possible, maintain and improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles) found in typical buildings constructed before the first standards were adopted in 1983.

The Power Act provides for broad application of the MCS. In the earlier plans, a strong emphasis was needed to improve residential and commercial building construction practices beyond the existing codes. Beginning with the first standards adopted in 1983, the Council has adopted a total of eight model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions to electric heating systems, the standard for conservation programs not covered explicitly by the other model conservation standards, and consistency in the application of federal and state appliance standards. Since the Council adopted its first MCS, all four states within the Northwest have adopted strong energy codes that largely incorporate the standards.

Model Conservation Standards

The MCS for the Ninth Power Plan has two distinct components. The first is that the Council adopts a region-wide standard for data centers based on the power usage effectiveness metric. This data center MCS references, and relies heavily on, ASHRAE 90.4-2022, *Energy Standards for Data Centers*. The second MCS for the Ninth Plan is for "retro-commissioning" of heat pumps. Retro-commissioning is essentially tuning up a heat pump to optimize its performance and reduce overall energy and demand.

Model Conservation Standard for Data Centers

The MCS for Data Centers in the Pacific Northwest for facilities over 300 kW is for Power Usage Effectiveness (PUE) to be at or below 1.20. These same data centers should also evaluate Peak Power Usage Effectiveness (PPUE). A PPUE value of 1.60 is recommended but not required. All new data centers shall report energy and water usage metrics (PUE, PPUE, and Water Usage Effectiveness, or WUE) to their local utility. Note that this MCS is not intended to apply to smaller facilities (e.g., data rooms in hospitals).

Background and Metrics

Data centers are a new large load coming to the region and this standard is aimed at ensuring that new data centers are being built efficiently. The most common metric for measuring data center electric efficiency is the Power Usage Effectiveness (PUE) metric. PUE represents the total data center electricity use divided by the total IT equipment electricity use:

$$PUE = \text{Total DC Energy Use}/\text{IT Equipment Energy Use}$$

A PUE of 1.0 means all data center energy is from the IT /server equipment and anything over that comes from other electricity uses such as air conditioning. Current modern data centers reach PUEs of 1.2.

Another metric that can be helpful for measuring the peak demand impacts of data centers is the Peak Power Usage Effectiveness (PPUE), which is the total peak demand in a single hour divided by the total IT peak load.

PPUE = Total peak load (single hour)/IT Peak Load

A third common metric used for data centers is Water Usage Effectiveness (WUE):

WUE = gallons of water consumed per kWh of electricity

The average is 0.5 gallons per kWh, but the amount depends heavily on the type of cooling system used: evaporative cooling will use significantly more water, but less electricity while vapor compression systems use no water but significantly more electricity.

The Council performed modeling of data centers[2] with a variety of cooling systems and in a variety of climate zones around the region. The objective was to evaluate the impacts of different mechanical system options for data center cooling. The results showed that overall, PUE values do not vary significantly by climate zone withing the region. Peak PUE values do vary more depending on the climate zone and cooling system type.

Data Center Model Conservation Standard

The MCS for data centers require all data centers over 300kW meet the following requirements:

All data centers to report to the utility:

- Energy consumption (electricity, natural gas, other)
- Water consumption
- PUE
- PPUE
- WUE

All new data centers are required to meet a **PUE of 1.20 or less.**

This requirement is three percent better than the 1.24 PUE specified by the ASHRAE 90.4 standard. ASHRAE 90.4 is fundamentally a voluntary performance standard and does not mandate the systems

[2] NWPCC Data Center Study: Climate Zones and Water Cooled Systems, PAE, May 22, 2026

or design approach used to meet the efficiency goal. However, Washington and Oregon have adopted ASHRAE 90.4 as the minimum performance for data centers in their states.

The reduction is based on reducing the mechanical loss component (MLC) from 0.14 to 0.10 in the relevant local climate zones, which is an achievable outcome for larger facilities. This effectively leaves electrical loss component (ELC) savings un-addressed.

Data Center Stretch Goals

In addition, local jurisdictions *may consider* stretch goals and targets as indicated below:

- New data centers over 300 kW could meet the following PUE values:
  - Air-cooled chillers shall meet PUE ≤ 1.17
  - Water cooled chillers shall meet PUE ≤ 1.14
  - Evaporatively cooled data centers shall meet PUE ≤ 1.10
- New data centers over 300 kW could meet the following PPUE values:
  - Air Cooled Chillers PPUE = 1.52
  - Water Cooled Chillers PPUE = 1.25
  - Evaporative cooling PPUE = 1.15
- All data centers shall evaluate and report WUE
- The cost of water consumption shall be included in the cost-effectiveness calculation

Model Conservation Standard for Heat Pump Retro-Commissioning

Background

According to the Air Conditioning Contractors of America (ACCA), a quality heat pump installation is characterized by four key areas:

- **Proper Design**: including load calculations and equipment selection
- **Proper Installation:** including static pressure, refrigerant charge, and controls
- **Proper (Air) Distribution:** including duct leakage and air balancing
- **Proper System Documentation and Owner Education**

Recent studies of heat pumps in the Northwest suggest that not all heat pumps are installed using these best practices, which often results in systems that do not operate as efficiently as they could. For example, there is evidence that load calculations are often not performed to properly size a heat pump. In this case, it is possible for the heat pump to be “undersized”, resulting in an overreliance on

less efficient auxiliary heating sources. Systems can also be "oversized", which can lead to other issues, such as short-cycling (a rapid on/off of the system that degrades overall performance).

Even if load calculations are performed and systems are sized correctly, there are other control settings and system checks that are critical to proper heat pump performance. For example, most heat pumps have control settings to "lock out", or effectively disable, both the heat pump's compressor and the auxiliary heating system under certain conditions. If these are not properly set, it is possible for a heat pump to not achieve its full efficiency potential.

Heat pumps that are not properly sized, commissioned, and controlled can lead to systems that put more demand on the electric grid, and cost more to consumers, than necessary.

Model Conservation Standard for Residential Ducted Heat Pump Retro-Commissioning

All heat pumps installed in the region should be properly commissioned, as well as properly sized and controlled, as outlined above. This MCS applies specifically to the retro-commissioning of existing residential ducted heat pumps already installed in the region, because this measure was found to be broadly cost-effective across the whole region. However, that does not diminish the fact that all heat pumps, including new installations in existing homes and new construction, should be properly commissioned, sized, and controlled for optimal efficiency.

The MCS requires that conservation program operators in the region, including Northwest utilities and Bonneville, offer programs to retroactively commission ("retro-commission") existing residential ducted heat pumps that may benefit from doing so. Such programs could be offered broadly, without specific targeting of homes that could particularly benefit from retro-commissioning, or more preferably, through targeted mechanisms, such as:

- identifying likely candidates via high monthly energy usage and/or high hourly demand; or
- identifying likely candidates via existing home audit conservation programs.

Such targeting activities could help maximize overall program cost effectiveness and minimize the number of heat pumps that would not benefit as much from retro-commissioning.

The target age for heat pumps going through this MCS program is approximately two to five years old. Those heat pumps are both old enough that they likely would not have received a recent retro-commissioning, but also new enough that they are expected to be in operation for another ten years or more.

The core strategy of the heat pump retro-commissioning MCS is to ensure that the heat pump is prioritizing its compressor as much as possible for space heating, and similarly de-prioritizing its auxiliary, or backup, electric resistance system as much as possible. Certain control settings can significantly increase the use of the backup system, thereby increasing energy use, demand, and occupant utility bills. Such control settings include:

- compressor lockout: typically, an outdoor temperature setting at which the heat pump's compressor is turned off. This should typically be set to as low a temperature as allowed, or completely disabled, allowing the compressor to run as much as possible.
- auxiliary lockout: typically an outdoor temperature setting at which the heat pump's auxiliary system is turned off, although can often be overridden by other control settings. This should typically be set near the heat pump's "balance point," or the outdoor temperature at which the heat pump can serve the home's entire heating load.
- emergency heat: a setting that typically disables the compressor completely and runs on the auxiliary system exclusively. This should never be used unless the compressor and/or other major heat pump components have failed.
- thermostat droop: a temperature differential setting that determines when the auxiliary system is engaged. Should be set to where occupant is comfortable, but auxiliary system is not engaged unnecessarily.
- thermostat night setback: turning down the thermostat temperature significantly at night and reverting to a higher temperature during the day. Can lead to significant overuse of the auxiliary heating system. If home occupant(s) desire night setbacks, some thermostats with intelligent setback recovery features may be used to mitigate setback effects.

In order to optimize these settings, it is important to understand important characteristics about the home's heating load and duct system. A table of specific recommended actions is provided in Table P - 1 below to serve as a general guide for what a MCS-compliant program should include. Importantly, an MCS-compliant retro-commissioning program would require more actions than the typical "heat pump tune-ups" already offered in much of the HVAC market; rather, a compliant program would include actions such as:

- accurate estimate of home heating load, to understand heat pump balance point and properly set auxiliary lockout
- testing of system airflow and total external static pressure, to ensure minimum requirements
- checking of thermostat and other system control settings
- checking of sufficient refrigerant charge and refrigerant line leaks and condition
- other activities as outlined in the table below

1 **Table P - 1: A general guide for recommended actions in a MCS-compliant heat pump retro-commissioning program.**

Equipment	Item	Recommended Action
Thermostat	Compressor Lockout	- Disable or set to as low of a temperature as allowed
	Auxiliary Lockout	- Set to 35°F as default. May be set lower depending on technician-verified heat pump balance point.
	Night Setback	- Verify need for night setback with home occupant. It setback is desired, enable intelligent setback recovery mode, if available.
	Emergency Heat Mode	- Verify system is not operating in emergency heat or similar auxiliary-only mode. Educate home occupant on implications of this setting.
	Supply Fan Setting	- Check to see if fan is set to On or Auto. Set to Auto, unless occupant desires constant fan.
	Thermostat Compatibility	- Check to see if thermostat is compatible with heat pump system.
Outdoor Unit	Coil Condition	- Check to see if coils are clean or dirty. Clean if needed.
	Refrigerant Leaks	- Check coil and flare connections (if present) for leaks using ultrasonic leak detector.
	Refrigerant Line Set	- Check to see if insulation is in good condition. If not, replace.
	Clearances/Airflow	- Ensure outdoor unit has proper clearances from snow and for airflow. For example, if side discharge, make sure unit is not blowing into a fence or wall.
Indoor Unit (Air Handler) and Ducts	Airflow	- Check airflow using TrueFlow plate or equivalent. Is airflow between 325 and 400 CFM per ton?
	Filter Condition	- Check condition. If dirty, clean or replace.
	Filter Size	- Check filter and filter grille size. Filter area should be at least 2 feet for each 400 CFM of airflow.
	Total External Static Pressure (TESP)	- Check TESP to make sure it is less than 0.8 in. water column (WC), and ideally near 0.3 to 0.6 in. WC. If greater than 1 in. WC, look for possible causes (e.g., plenum is too small).
	Refrigerant Leaks	- Check coil for leaks using an ultrasonic leak detector.
	Coil Condition	- Check coil for dust buildup, and clean if needed.
	Air Leaks	- Check for air leaks near the air handling unit, such as the cabinet seams or plenum connections.
	Condensate Drain Pans	- Was condensate pan and trap installed correctly? Does it need cleaning? Is there a secondary drain pan in the attic? If so, is there a leak sensor?
	Supply Registers	- Are supply registers unobstructed and providing conditioned air?

2

Other Conservation Program Details

Additional Guidance for Heat Pump Ready Homes

The Conservation Program in Chapter 5 includes a recommendation for conservation programs in the region to promote the concept of making homes "heat pump ready." While there are a number of actions that can technically fall under the umbrella of making homes more heat pump ready, this specific recommendation is focused on weatherizing, air sealing, and improving the duct systems of homes before they receive a heat pump, as this is a highly effective way of ensuring that heat pumps operate as efficiently as possible.

How much weatherization, air sealing, and duct improvements are enough before a heat pump installation? While there is not a single correct answer to this question, the Council, informed by its advisory committees, believes some general guidance on this topic could be useful for conservation program operators in the region pursuing heat pump readiness. Table P - 2 below provides general guidance on minimum and preferred weatherization, air sealing, and duct characteristic levels for installing a heat pump in an existing home in the region. Note that this guidance is intended primarily for homes built before energy codes (e.g., pre-1980), as these homes are the most likely to not meet the specifications in the table below.

1 **Table P - 2: Recommended minimum and preferred efficiency levels for a heat pump ready home.**

Element	Item	Recommended Minimum/Preferred Efficiency Level
Building Shell	Wall Insulation	Filled wall cavity (~R11 for 2x4 walls, ~R19 for 2x6 walls) or R10 continuous
	Attic/Roof Insulation	Attics: R38 cavity minimum, R49-60 preferred Sloped Ceiling/Roof: R19 cavity or R15 continuous
	Floor/Foundation Insulation	Insulated floor: R19 cavity minimum, R25 preferred Insulated foundation walls: R10 continuous minimum, R15 continuous preferred
	Windows	U-0.5 (double-pane) minimum, U-0.3 (double-pane) preferred
	Air Leakage	9 ACH50[3] maximum, 6 ACH50 preferred
Duct System	Duct Insulation	Rigid duct (unconditioned space): R6 minimum, R8 preferred Flex duct (unconditioned space): R4 minimum, R6 preferred
	Duct Leakage	15% leakage to outside maximum; 10% or less preferred
	Duct Airflow	325 CFM per ton minimum, 400 CFM per ton preferred (or manufacturer specification)
	Duct Total External Static Pressure (TESP)	0.8 in. water column (WC) maximum; 0.3 to 0.5 in. WC preferred (or manufacturer specification)

2

[3] Air Changes per Hour, at 50 Pascals.

Surcharge Recommendation

The Power Act authorizes the Council to recommend a surcharge and the Bonneville Administrator may thereafter impose such a surcharge on customers that have not implemented conservation measures that achieve energy savings comparable to those which would be obtained under the MCS in the plan. The Council does not recommend a surcharge to the Administrator under Section 4(f) (2) of the Act at this time.

The Council intends to continue to track regional progress toward the Plan's MCS and will review its decision on the recommendation should accomplishment of these goals appear to be in jeopardy. Should utilities fail to enact these standards, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the Administrator be granted the authority to place a surcharge on that customer's rates to recover those costs.

Surcharge Methodology

Section 4(f)(2) of the Northwest Power Act directs the Council to include a surcharge methodology in the power plan. The surcharge must, per the Act, be no less than 10 percent and no more than 50 percent of the Administrator's applicable rates for a customer's load or portion of load. The surcharge is to be applied to Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards.

The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth.

As stated above, the Council does not recommend that the Administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge calculation for Bonneville's administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is set out below.

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards set forth within this chapter.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.
2. If the customer is not purchasing firm power from Bonneville under a power sales contract, but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

Technical Appendix Q: Analysis of Dual Versus Single Target for Conservation

Contents

Introduction 1
Context of Proposed Dual Conservation Target 2
Enhanced Modeling Framework 2
Results from Scenario Modeling 4
Council Analysis 9
Assessing Implications of a Single Target 11
Shift in Conservation 11
Portfolios Costs 14
Regional Adequacy 16
Summary 18
Seeking Public Comment 18

Introduction

This technical appendix provides analysis comparing a "dual target" and a "single target" for conservation, within the agreed to resource portfolio as proposed in the draft Ninth Power Plan (see Action Item RES-1 in Chapter 4 for the recommended resource strategy).[1] The conservation target recommended in the draft Plan is 1,060 aMW regionally by 2032.[2] The question that the Council wrestled with in the development of the target was whether and how to allocate those aMW across the region. Should the Council create multiple sets of avoided costs across the region reflecting the

[1] The regional resource strategy includes 1,060 aMW of conservation, 590 MW of demand response, 220 MW of voltage regulation, 9,000 MW of renewables, 5,200 MW of storage, and 2,100 MW of natural gas. The analysis in this technical appendix assumes the amounts for all those resources remain the same.
[2] The level of investment assumed under the dual target included in the draft Plan would result in 3,950 aMW by 2046.

locational value signal from scenario modeling, or should the Council assume one set of avoided costs under a single target approach?

The draft Power Plan puts forward a "dual target" that creates two different sets of avoided costs for the region: one set for Oregon and Washington and another set for Idaho and Montana. This approach of a dual target is a shift away from the Council's historical approach of a single, regional conservation target. During the development of the draft Plan, the Council received comments from many entities expressing concern regarding the inclusion of a dual target for conservation. Before releasing the draft Power Plan, the Council asked staff to develop this technical appendix to explore some of the trade-offs between a dual versus single target, assuming the overall proposed regional resource strategy remains the same.

The Council is interested in continuing this conversation during the public comment period. This technical appendix aims to support those conversations. The appendix starts with a discussion of the Council's enhanced modeling framework that provided improved information around the locational value of resources. It then walks through the locational signal for resources from the scenario modeling and how the Council used those results to develop the dual target approach included in the draft Plan. The final section walks through staff's analysis of the implications on costs and adequacy of shifting to a single target approach.

Context of Proposed Dual Conservation Target

Enhanced Modeling Framework

The inclusion of a dual target in this draft Power Plan started with the Council's enhancements to its modeling infrastructure. For the Ninth Power Plan, the Council upgraded its suite of modeling tools, which provides more granularity in analysis. This includes more granularity in the timescale of analysis (i.e. the ability to model hourly dynamics of the power system), as well as increased geographic granularity.[3] The sections below provide more context around the value of more geographic granularity in power planning.

Load Forecasting

One of the enhanced tools was the use of Itron for the development of the Council's load forecast. This allowed the Council to develop different load forecasts for the region's 13 balancing authorities.[4]

[3] Technical Appendix A – Global Assumptions outlines the modeling zones assumed in the load forecasting and scenario modeling. More information about the development of specific locational assumptions can also be found in other technical appendices, including Technical Appendices G through J that describe the development of regional resource potential estimates.

[4] Technical Appendix F – Electricity Demand Forecast provides details of the Ninth Plan load forecast, including locational differences driving differential load growth.

The ability to forecast loads at a more granular level is a critical enhancement of the Council's Ninth Power Plan, as new forecasted loads are coming in different forms to different parts of the region.

The Ninth Plan pulls together forecasts from all the different load sectors. Core to the forecast is the growth in the residential, commercial, industrial, and agricultural sectors. Changes in these loads are driven by changing populations and economics, among other factors. The Ninth Plan forecast shows the largest growth rates for these sectors in Idaho and Montana.

In addition to these core loads, the Ninth Plan forecast also includes growth of new sectors, including the electrification of end uses and the addition of more data center and high-tech loads. These sectors show different trajectories across the region. Driven in part by policies, electric vehicles and the electrification of other end uses is mostly occurring in the states of Oregon and Washington. This growth tends to be concentrated in urban centers, particularly impacting the Puget Sound and Portland areas. Of all the load growth, the electrification of transportation and buildings contributes most significantly to peak load impacts by the end of the 2046 forecast period. Concentrated growth of electrification loads will create unique resource needs relative to other parts of the region with slower or flatter load growth.

The other area of significant growth is data centers and the high-tech industry. These new loads are large and relatively flat in profile. The Ninth Plan forecasts these loads in specific zones, primarily Central Oregon, the Portland area, the Mid-Columbia utility zones, and in Idaho Power territory. The concentrated growth drives up energy needs for these specific zones in a way that is unique from other zones of the region not experiencing this load growth.

Taken collectively, the Ninth Plan shows significant load growth in the states of Washington and Oregon, driven by a mix of data centers and electrification. The Ninth Plan also shows significant growth in parts of Idaho, impacting both energy needs and peaks.

Resource Potential

Just as loads are not uniform across the region, neither is the potential for new resources. On the demand side, the potential for new resources is tied directly to the loads. The forecasted growth in homes and businesses in a specific zone directly impacts the forecasted demand-side resource potential of that zone. The Council also had data to support different within zone transmission and distribution deferral values (T&D deferral) for the west and the east sides of the region.[5] This analysis showed increased value for conservation to defer T&D on the west side of the region compared to the east side of the region. Those assumptions were included in the Council's supply curves for demand side resources and had the impact of slightly lowering the levelized cost of resources on the west side relative to the east. Beyond the different T&D deferral values, the Council did not have data to further differentiate demand-side resource potential by zone (e.g. differential baseline assumptions or costs), but such data would improve estimates of technical potential in the future.

[5] Technical Appendix A – Global Assumptions provides more details on the analysis behind the T&D deferral values.

On the supply side, resources may be limited by policy, land, transmission, fuel, and other factors.[6] The Council's Ninth Plan captured that diversity by only allowing resources in specific zones. For example, new natural gas was excluded from the Oregon zones based on policy. While new natural gas beyond Oregon was not limited by policy, the Ninth Plan analysis excluded it from heavily urban zones such as Seattle and Tacoma for practicality reasons. Renewables were similarly limited in the model. New wind was excluded from urban areas, including the Puget Sound and Portland area zones. New large, utility-scale solar was excluded from the most densely populated urban areas (e.g. Puget Sound zones), with small scale solar being the only renewable option for these zones.

In addition to resource availability, the Ninth Plan also captured differences in the shape of resources driven by fuel availability. The Council created five different wind reference plants to account for the varied availability and quality of the wind resource across the region. The Council also created three different solar reference plants to account for the diversity of the solar resource across the region. This provided important information to the model around the timing and availability of these resources, which impact the economics and value of the resource.

Taken collectively, there are certain portions of the region with more limited access to generating resources. Particularly the urban zones with limited land have fewer new resource options available. This in turn requires an understanding of transmission capability, and the ability to develop remote resources and deliver that energy to the load centers. The zonal modeling therefore also included information on transmission capacity and overall connectivity between zones.

Results from Scenario Modeling

The scenario modeling for the Ninth Plan demonstrated the locational value for several resources, including conservation. This section provides a high-level discussion on the location-specific results. More information on the scenario modeling results is available in Technical Appendix N.

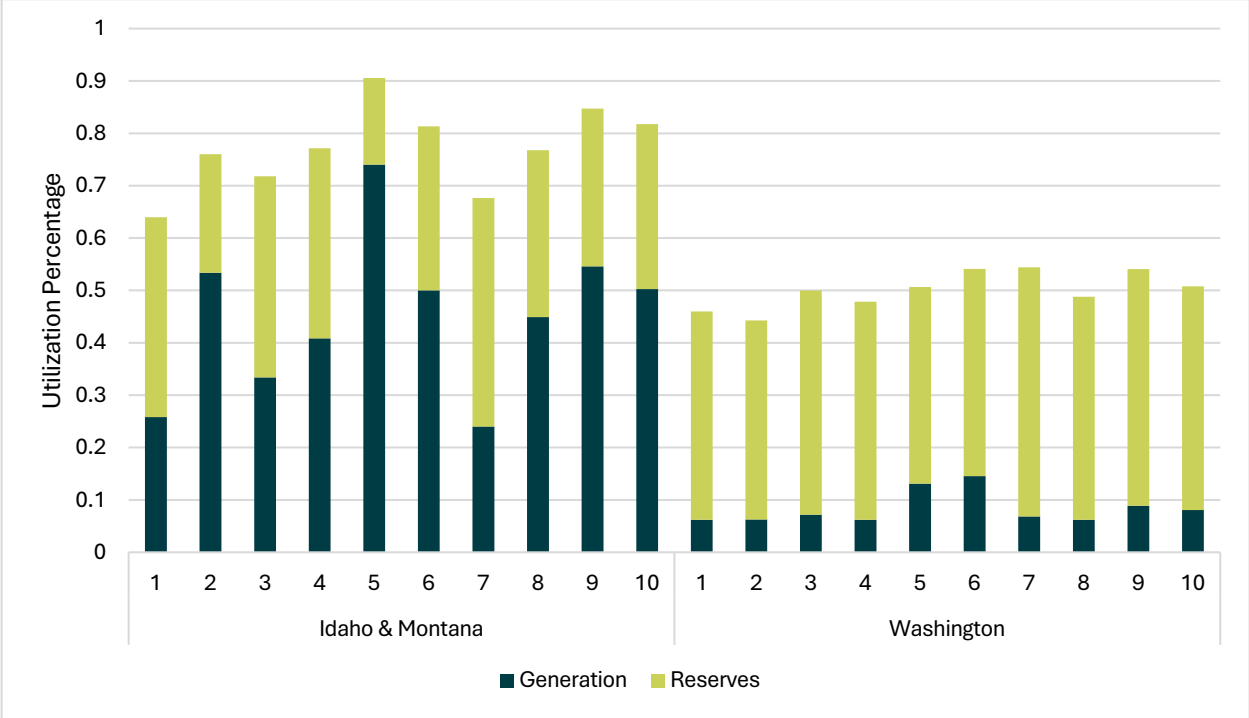
Locational Value of Supply Side Resources

On the supply side, the modeling showed different signals for the selection and operation of resources based on location. The model primarily acquired new natural gas in zones in Idaho and Montana, with fewer units acquired in Washington zones. Once acquired, the utilization of those new thermal units also varied. The bulk of new natural gas acquired, particularly in the near-term, was peaking plants. These plants were generally utilized more to provide seasonal reserves, generating more in the modeled futures with low hydro. That amount of generation varied by zone, with greater generation in Idaho and Montana as compared to Washington. One driver for this is the carbon market in Washington, which increases the cost of natural gas generation. Figure Q - 1 shows the utilization of

[6] More discussion on the locational differences for generating resources is available in Technical Appendix G – New Generating Resources.

new thermal units in 2032, grouped by new units in Idaho and Montana versus those in Washington.[7] This provides a clear example of how new resources are utilized differently across the region, given differences in economics and policy.

Figure Q - 1: Utilization of New Thermal Units in 2032 Across Sensitivities



This translates to differing levelized costs of energy for the new natural gas resources. The new natural gas in the Idaho Power zone is generally utilized the most for generation (instead of reserves). This brings down the levelized cost of the resource, with levelized costs as low as $50/MWh and going up to $75/MWh. The costs in broader Idaho and Montana zones were a bit higher, ranging between $80-$100/MWh. The carbon market in Washington both drives up the cost of generation and reduces the amount of generation. The resulting levelized cost of energy for new gas in Washington ranges between $120-$170/MWh.

The modeling also showed locational differences for solar. The bulk of standalone solar was acquired east of the Cascades, where the solar resource is better. Solar is acquired in zones west of the Cascades, but that was generally either more expensive smaller scale solar (because the large scale solar was not available in a zone) or hybrid solar plus storage resources where the added storage helps to expand the value of the solar in zones with generally less sunshine.

[7] The data in Figure Q - 1 is averaged across all 13 sensitivities. In other words, Future 1 represents the average utilization for all Future 1s in each of the 13 sensitivities. This was done as the general trend in utilization is consistent across sensitivities, with greater variability being the difference across zones and futures.

The wind acquisition was different. Rather than concentrating all new wind in those zones with the best shape (and therefore economics), the model acquired wind more broadly across the region. This demonstrated the value in the diversity of the wind resource. This finding is consistent with other studies, including market studies conducted by the Council, which show the value in diversity of renewables across a footprint.

Locational Value of Conservation

On the demand side, conservation was the one resource that showed locational value. Throughout development of the draft Plan, several entities have asked why other demand side resources do not also show a locational value. This appears to be based on the overall value of those other resources as seen in the scenario modeling. For example, voltage optimization is one of the lowest cost resources available to the model and is therefore seen as economical in all zones being acquired in the full amount available to the model in every sensitivity. The model did show locational differences in how this resource was utilized, with the model preferring more of a conservation approach to this resource on the west side and more of a demand response approach on the east. Behind-the-meter solar is one of the more expensive resources and is therefore only selected in the one sensitivity when other resources are significantly limited (the Constrained World). Demand response is selected in some amount in every sensitivity, but generally just the lowest cost bin is acquired. The modeling of this resource does not capture a strong economic value for the resource generally, thereby minimizing a signal for the locational value for the resource. Additionally, the model does not capture within zone constraints, contractual challenges, or other barriers that might change the value for demand response for certain jurisdictions.[8]

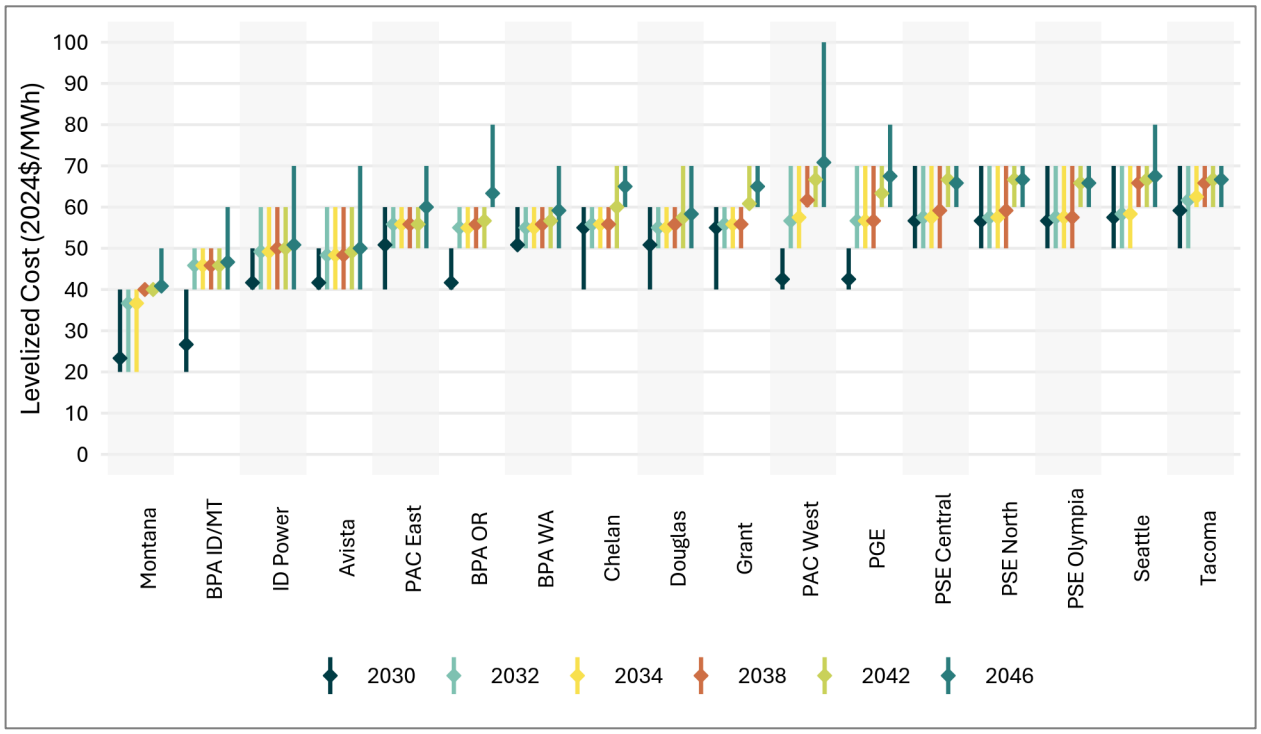
Conservation on the other hand showed a clear signal for locational value. This, in part, is likely due to the nature of the resource. With levelized costs ranging from $0 to over $250/MWh, the model had a wide range of potential conservation to select from. Additionally, the scenario modeling showed a strong preference for resources that both provide energy and support the planning resource margins, which conservation does. Taken together, there is a strong signal for the value of a resource like conservation, and the range in available costs allowed the model to select that conservation that is economic for each zone relative to other resources.

The scenario modeling shows a consistent signal of a varied value for conservation across the region. Figure Q - 2 provides information on the range and average levelized cost of conservation acquired across the zones for the different sensitivities. For each zone, the range captures the difference between the sensitivity with the lowest cost of conservation acquired and the sensitivity with the highest cost of conservation acquired. The diamond marks the average cost acquired across the 13 sensitivities for that zone. For example, the first range in the Montana zone shows that for 2030, the model purchased up to $20/MWh on the low end and up to $40/MWh on the high end, with an average

[8] The modeling of demand response is discussed elsewhere in the draft Ninth Plan including Chapter 4 and Technical Appendix N – Scenario Modeling Results. Please refer to those areas for a deeper discussion on the limitations of demand response modeling for this Power Plan.

of around $22/MWh. Whereas the Tacoma zone for that same 2030 year, purchased up to $50/MWh on the low end and $70/MWh on the high end, with an average around $60/MWh. In other words, in 2030, on average, conservation was economic in the Montana zone at around $22/MWh and economic in the Tacoma zone at around $60/MWh.

Figure Q - 2: Average Levelized Cost Per Zone, Across Sensitivities



As shown in Figure Q - 2, Montana consistently showed the lowest value for conservation, meaning less costly conservation was economical in Montana to meet needs relative to other resources. The load growth in Montana, while still significant relative to their current loads, is relatively smaller than in other parts of the region. The Council's forecast does not assume significant loads from electrification or additions of data centers. At the same time, Montana has one of the best wind resources in the region, with the levelized cost of wind for those zones coming in around $35/MWh.

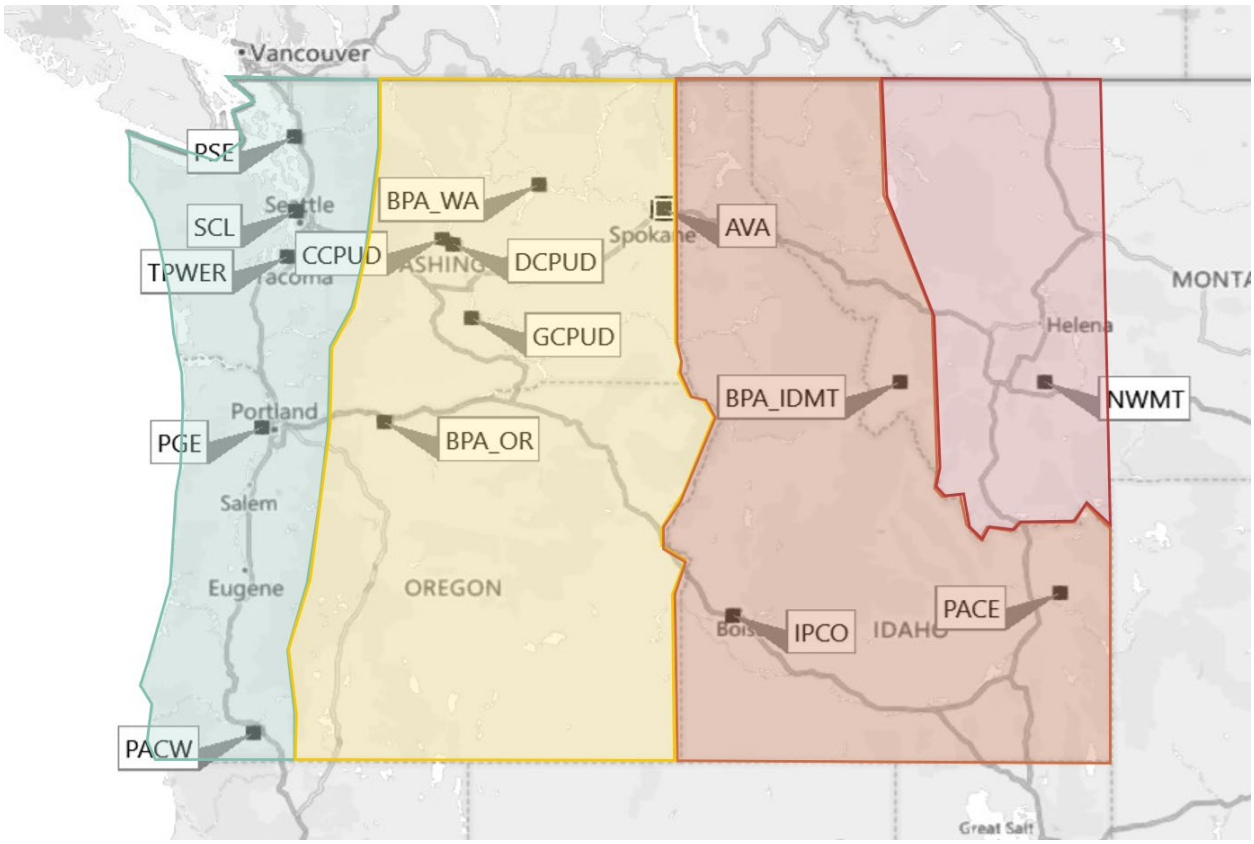
On the other side of the region, the Puget Sound Area zones (PSE Central, PSE North, PSE Olympia, Seattle, and Tacoma) consistently showed the highest value for conservation, particularly in the early years. While these zones are not experiencing forecasted growth from data centers, electrification is driving up the loads (particularly peaks) in these areas. Additionally, as discussed above, there are fewer supply side resources available to directly serve these zones, meaning resources need to be developed remotely and delivered to load via transmission. Constraints in transmission capacity also increases the value in acquiring conservation to lower loads.

Another differentiating factor between conservation locations is clean policies and goals. The Ninth Power Plan includes policies and utility goals for carbon reduction throughout the western grid. For Washington specifically, the model includes planning with the social cost of carbon due to the Clean

Energy Transformation Act (CETA) requirements. These requirements can be offset by Washington-based conservation in the model, providing additional locational value.

The scenario modeling also showed different market prices across the region, suggesting differential value for resources that defer the need for market purchases. The market prices are highest in some of the Puget Sound area zones and lowest in the Montana zones. A weighted average market price across the sensitivities for the west side (Oregon and Washington) is around $34/MWh and the weighted average market price for the east side (Idaho and Montana) is around $26/MWh.

Figure Q - 3: Relative Value of Conservation Across the Region



The locational results generally group into four zones: West of the Cascades, East of the Cascades in Oregon and Washington, Idaho, and Montana (see Figure Q - 3). These results are consistent with the realities on the ground.

- **West of the Cascades:** These zones are experiencing load growth driven by electrification, and in some cases tech loads (around Portland). The availability of new generating resources is limited, particularly around the Puget Sound area and in urban centers. New natural gas cannot be built in Oregon, and the carbon market in Washington makes new natural gas less economic. Additionally, there are transmission constraints across the Cascades that limit the viability of developing lower cost resources remotely to serve loads.
- **East of the Cascades in Oregon and Washington:** These zones are also experiencing load growth driven by electrification, albeit less than in the urban centers on the west side of the

Cascades. Rather, the biggest driver of loads in these zones is from high tech loads. On the resource side, more resources are available. Additionally, there are fewer transmission constraints limiting the ability to bring resources to load. One key factor that sets this area apart from the zones further east is policy: new natural gas cannot be built in Oregon, and the same policy drivers limiting natural gas west of the Cascades in Washington impact the east side of Washington. As noted above, the levelized cost of energy for new natural gas in Washington is between $120 and $150/MWh, making more conservation cost-effective at these levels as compared to Idaho and Montana.

- **Idaho:** There is significant forecasted load growth in Idaho, particularly in the Idaho Power zone in and around Boise. This is driven by growth in the high-tech sector, as well as growth in the residential and commercial sectors, which are increasing both energy and peak needs. There are more resources available that can be developed closer to loads to meet this growth in Idaho. Also, without a carbon market, new natural gas becomes more economic. Idaho has greater transmission connectivity to the broader WECC, increasing the ability to bring remote resources to load.
- **Montana:** As discussed above, while the Council's load forecast estimates significant load growth for Montana, the overall amount continues to be less than the other states. Neither electrification nor new high-tech sector loads are forecasted in large amounts in this part of the region. At the same time, similar to Idaho, there are more resources available that can be developed closer to meet load growth, and these resources are generally more economic than the higher cost conservation.

These factors result in conservation being cost competitive only up to the comparable price of competing natural gas and renewable resources. The Council used this analysis to inform the proposed conservation target approach for the draft Power Plan, as discussed more below.

Council Analysis

The Council is required to put forward a scheme of new conservation and generating resources to meet future needs, prioritizing cost-effective resources. The scenario modeling demonstrated that conservation is cost-effective at different amounts across the region, driven by differences in load growth, resource availability, and policy. Striving to prioritize cost-effectiveness, the Council developed a proposed conservation target to reflect at least some of these locational differences.

Council staff discussed the scenario modeling results with the Council's Conservation Resources Advisory Committee (CRAC) and sought feedback on how best to use the locational information in developing the conservation target to be included in the draft power plan. The CRAC members expressed a range of perspectives. There was some support for leveraging the locational signal in developing a target. One member suggested that any differences in the target be connected to state boundaries as driven by policies. At the same time, several CRAC members expressed concerns about risks of moving towards a multiple target approach, particularly noting concerns around

implementation challenges for Bonneville and NEEA.[9] As a whole, the CRAC generally recognized that there were pros and cons with pursuing either a single target or multiple target solution.

Considering this feedback and the Power Act requirements, staff proposed pursuing a two-target approach defined by state boundaries. While the analysis suggested more potential zones (four or five), staff were cognizant of the implementation concerns raised at the CRAC. The two-target approach was proposed to provide some balance between leveraging the locational information from the scenario modeling results while seeking minimizing the implementation challenges. Aligning the target by states provides cleaner boundaries for implementing the target, while also recognizing the real policy differences across the region that are driving some of the cost-effectiveness results of the conservation modeling.

The Council recognizes that there are other ways it could use the locational information to develop a dual (or more) conservation target. For example, given the very strong signal for conservation west of the Cascades, the Council could set a target for those jurisdictions. This geographic boundary has a strong logical basis, given the transmission constraints across the Cascades and the limited land availability for renewables west of the Cascades. A geographic boundary, such as the Cascades, may be more challenging to implement, but the Council could develop an approach to support the region in assessing whether an entity is in that zone or not (similar to the Regional Technical Forum's development of heating and cooling zone mapping for relevant conservation measures).

Building on this approach, the rest of the region could be put into a single zone, or further split based on other boundaries. A single zone east of the Cascades recognizes that implementation of conservation for entities in Washington and Oregon on the east side of the Cascades is similar to those in Idaho and Montana. At the same time, it glosses over real differences between the resource needs in Oregon and Washington, as compared to Idaho and Montana, in response to decarbonization policies. The modeling also supports different targets for Idaho and Montana, largely driven by different load growth forecasts and needs. Much of the Idaho signal is likely driven by the significant load growth in Idaho Power's territory from high-tech loads, suggesting perhaps further bifurcation. The point being, there are many ways the locational information could be leveraged to capture the on the ground realities of the region's diversity. Additionally, any approach carries some challenges with no single zone being uniform in needs and would require shifts in implementation from a single target approach.

Another factor in developing the conservation amount included in the draft Plan was the overall scenario modeling results. The scenario modeling showed that more conservation is part of a cost-effective portfolio when resources are constrained on the supply side. (This is consistent with the

[9] Since this discussion at the CRAC, Bonneville has shared more information at the Council regarding their concerns about the implementation challenges associated with a dual target. These include restructuring to operations and tools, with potential to increase administrative and infrastructure cost increases. At this time, the Council does not have enough specificity to analyze these considerations with other factors discussed elsewhere in this appendix. The Council continues to have conversations with Bonneville, and will do so throughout the public comment period, with a goal of better understanding the specific concerns and working to identify potential paths forward.

locational information described above, where more conservation is acquired in those zones with fewer resource options.) The scenario modeling also showed that, universally, more expensive conservation is required over the long-term to support adequacy (i.e., conservation has generally more value by 2046 than it does in 2032). The Council developed a conservation target for this draft Plan that provides a hedge for both the near-term supply side risks and long-term adequacy needs.

Assessing Implications of a Single Target

This section walks through considerations of a single target from a resource planning perspective. As discussed earlier in this appendix, the assumption underlying this analysis is that the same level of conservation would be part of the resource strategy (e.g. 1,060 aMW). The only difference is that rather than having two different avoided costs as defined by the dual target, the single target assumes a single avoided cost for the region. In other words, conservation has the same value in all parts of the region.

Shift in Conservation

The dual target as recommended in the draft Ninth Power Plan assumes two different levelized costs for conservation: up to $150/MWh for Washington and Oregon representing an average cost of around $45/MWh and up to $70/MWh for Idaho and Montana representing an average cost of around $32/MWh. Shifting this to a single conservation target means moving to a single assumed levelized cost for the region. At 1,060 aMW of conservation in 2032, a single target would be up to $107/MWh of conservation regionally, which equates to an average cost of around $40/MWh.

Shifting Cost-Effective Conservation Eastward

A single target shifts cost-effective conservation potential from the west side of the region to the east. Since the underlying assumption of this analysis is to maintain 1,060 aMW of conservation regionally, the reduction in conservation on the west side of the region exactly equals the increase on the east side. By lowering the cost-effectiveness threshold from $150/MWh to $107/MWh, the west side loses around 40 aMW of cost-effective conservation. This 40 aMW is then added to the east side, representing the difference of the increased threshold from $70/MWh or $107/MWh.

Table Q - 1: Amount of Cost-Effective Conservation by Zone in 2032

Zone	Dual Target	Single Target
Oregon and Washington	860 aMW	820 aMW
Idaho and Montana	200 aMW	240 aMW
Regionally	1,060 aMW	1,060 aMW

Reduction in Long-Term Investment in Conservation

Assuming continued investment at the levels proposed under the dual target in this draft Power Plan, the overall conservation acquired at the regional level by 2046 would be 4,220 aMW. Under a single

target, this amount is less. The lower investment level on the west side of the region (up to $107 instead of up to $150) results in around 270 aMW less conservation by the end of the plan. That is offset slightly by the increased investment on the east side of the region, with an increase of around 160 aMW. Overall, this results in a reduction of 110 aMW of conservation regionally by 2046.

Table Q - 2: Amount of Cost-Effective Conservation by Zone in 2046

Zone	Dual Target	Single Target
Oregon and Washington	3,530 aMW	3,260 aMW
Idaho and Montana	690 aMW	850 aMW
Regionally	4,220 aMW	4,110 aMW

More Cost-Effective Measures in Idaho and Montana

This shift in the amount of cost-effective conservation available in each part of the region drives a change in the specific measures that are available as cost-effective. The additional 40 aMW of cost-effective conservation in the east results in more measures becoming available. In many cases, this increase does not represent an entirely new measure becoming available, but rather expanded applications of the same measure.

The bulk of the additional measures available between $70 and $107/MWh are in the residential sector. Table Q - 3 summarizes these available measures. Most of this is in additional weatherization applications, specifically insulation measures for attics, walls, and floors.

Table Q - 3: Residential Measure Additions in Idaho and Montana Under Single Target

Measure	Available Up to $70/MWh	Additional Available Up to $107	Single Target Total
Air Source Heat Pump Upgrade		6.69	6.69
Central Air Conditioning		0.40	0.40
Weatherization	6.84	11.1	17.94
Refrigerator	0.75	1.20	1.95
Freezer	0.28	0.38	0.66
Residential Total	**7.78**	**19.67**	**27.55**

Additional measures and measure applications also are available in the commercial, industrial, and agricultural sectors when going from $70/MWh to $107/MWh. This is a mix of heating and cooling measures, lighting, pumps, and grocery measures.

The total technical potential for conservation in Idaho and Montana estimated for 2032 is around 320 aMW. Of this, the dual target recommends that 200 aMW of that technical potential is cost-effective, leaving roughly 120 aMW as not cost-effective. Shifting to a single target, the addition of 40 aMW means that 240 aMW would be cost-effective, with only 80 aMW of the total technical potential being not cost-effective at the measure level. This equates to about 75% of the technical potential being cost-effective on the east side. The bulk of the remaining non-cost-effective potential (around 65 aMW) is from residential measures, primarily heating and cooling measures. This includes air source heat pumps and ductless heat pumps.[10]

Fewer Cost-Effective Measures in Washington and Oregon

The lower cost-effectiveness threshold on the west side of the region means that fewer measures are cost effective. The bulk of this reduction (around 75%) comes in the loss of measures for the commercial sector. Table Q - 4 shows the reduction in commercial conservation measures, focusing on the end uses. The bulk of the loss (close to 14 aMW) comes from heating, cooling and ventilation (HVAC) measures. The next big difference is in measures for grocery refrigeration.

Table Q - 4: Commercial Measure Reductions in Oregon and Washington Under Single Target

End Use	Available Up to $150/MWh	Reduction between $150 and $107	Single Target Total
Appliances	2.50	0.01	2.49
Compressed Air	0.79	--	0.79
Electronics	25.05	--	25.05
Food Preparation	3.95	0.23	3.71
HVAC	150.54	13.71	136.83
Lighting	28.12	3.52	24.60
Motors/Drives	5.66	0.67	4.98

[10] These measures (air source heat pump upgrades and ductless heat pumps) are not currently cost-effective at the measure level under the 2021 Power Plan, nor would they be under either the Council's proposed dual target approach for the Ninth Plan. This means that acquiring these resources costs more than otherwise acquiring an alternative similarly available and reliable resource, whether that be conservation or a generating resource. Technical Appendix H – Conservation Methodology and Potential provides more details on the estimated levelized cost of the conservation potential for the region.

End Use	Available Up to $150/MWh	Reduction between $150 and $107	Single Target Total
Other	0.46	0.13	0.32
Refrigeration	35.85	7.75	28.10
Vehicles	10.98	--	10.98
Water Heating	13.03	1.35	11.69
Whole Building	26.81	--	26.81
Total	**303.72**	**27.37**	**276.35**

Additional measures in the residential, industrial, and agricultural sectors also become not cost-effective. This includes applications of residential weatherization (insulation primarily) and some central air-conditioning measures.

The total technical potential assumed for the west side is around 1,200 aMW by 2032. Of this, 860 is cost-effective under the dual target with 340 aMW not being cost-effective. Shifting to the single target approach results in 820 aMW of cost-effective conservation, with 380 aMW being not cost-effective at the measure level. This equates to roughly 68% of the technical potential on the west side being cost-effective. Also, similar to Idaho and Montana, the bulk of the remaining non-cost-effective measures are in the residential sector. This includes the same air source heat pump and ductless heat pump measures that are not considered cost-effective for Idaho and Montana.[11]

Portfolios Costs

Council staff assessed the difference in portfolio costs between a dual target approach and a single target approach. As noted earlier in this appendix, this analysis assumed that all other elements of the regional resource portfolio remained the same, with the only difference being in conservation. Specifically, the key difference was analyzing the costs assuming the 40 aMW shift of conservation from the west side of the region to the east side of the region.

Fixed Costs

There are two cost elements as part of a portfolio. The first is the fixed costs. These costs represent the annual investment for acquiring the resources, as well as fixed operations and maintenance cost based on the portfolio, including the existing system, previous investment, and current investment. There is one set of fixed costs for any portfolio based on the resources that make up that portfolio.

[11] Technical Appendix H – Conservation Methodology and Potential provides more information on the technical potential for the region.

When comparing the fixed costs of the portfolio for the dual versus single target for conservation, the only difference is in the costs for the conservation itself. This includes the reduced investment on the west side (the direct cost of the 40 aMW reduction of conservation between $107/MWh and $150/MWh) and increased investment on the east side (the direct cost of the added 40 aMW of conservation between $70/MWh and $107/MWh). Regionally, this shift results in a reduction in the annual fixed costs of around $18 million dollars for year 2032 (in 2024 dollars). That is approximately a 0.8% reduction in fixed costs in 2032 for the portfolio.

Since fixed costs for conservation can be directly attributed to the utilities acquiring the resource, it is possible to assess how changes to the fixed cost impact the region differentially. Analysis shows that while the overall fixed cost of the portfolio decreases, the decrease is not universal. The reduction in 40 aMW of conservation on the west side reduces annual direct costs for those utilities by around $47 million in 2032. Shifting that conservation to the east side results in an increase in the direct costs for those utilities by around $29 million. It is that net difference that results in the $18 million reduction in direct costs regionally.

It is worth noting that this analysis just explores the difference in the fixed cost of the conservation. What is not included is who is assumed to pay the fixed costs associated with other resources in the portfolio, as these can be developed remote from load. As cost-effective conservation shifts from the west side of the region to the east side of the region, west side utilities will be required to acquire other resources in the resource strategy to meet needs. Similarly, more conservation acquired on the east would likely reduce the need for those utilities to acquire other resources in the strategy. Without knowing those specific shifts for each utility, the Council cannot provide a full analysis of how the overall fixed costs between a dual and single target for conservation would impact any utility or zone.

Variable Costs

The variable costs are the second element of portfolio costs. These costs represent the production costs of the portfolio, which include the variable costs associated with fuel, transmission, policies, and variable operations and maintenance. Unlike the fixed costs, the variable costs change for the portfolio depending on the future tested. For example, in years with low hydro conditions, the system relies more on natural gas generation to maintain adequacy. This will increase the variable costs in that year relative to a high hydro generation year, due to increased costs for fuel and for compliance with policy.

When comparing the variable costs of the portfolio for the dual versus single target, the variable costs are much closer between the portfolios, with the annual 2032 variable costs of the dual target being roughly $3.7 million dollars less than those of the single target. A portion of this ($3.4 million) is driven by a difference in operations costs (e.g. fuel and transmission) and the remaining is connected to a very slight increase in emissions-related costs. This shows that, on average, there is slightly more thermal generation under a single target portfolio than under the dual target, although this is within the range seen across the futures assessed for either portfolio.

Given all costs incorporated in these portfolio variable costs, it is not possible to do an analysis of how those will impact different utilities within zones. For example, because part of the variable costs

are connected to natural gas fuel costs, without knowing where and who is responsible for those costs, it is not feasible for the Council to connect those costs to specific utilities.

Total Costs

Combining the fixed and variable costs, the single target portfolio annual cost is approximately $14 million less than the dual target portfolio. Putting this into perspective, $14 million represents less than 0.5% of the overall annual cost for the portfolio.[12] This is also significantly less than the difference in overall portfolio costs across the futures tested in the scenario modeling. In that context, Council staff find that these two portfolios have similar total costs.

Regional Adequacy

The final element of this analysis for this technical appendix was to test the proposed regional resource strategy, but assuming a single target, for adequacy. To do this, the Council set up a full adequacy check consistent with the check for the proposed strategy, with the only difference being in the location of conservation as informed by the single target and discussed above.[13] Both assessments focused on 2031, assumed the same additions of generating resources, used the same hydro operations for fish and wildlife, and analyzed the same range of future load trajectories and hydro and variable energy resource availability.

The Council uses a multiple metric approach to test for adequacy. These metrics seek to ensure that modeled shortfalls are not too frequent, nor are they too long or too large.[14] Table Q - 5 compares the adequacy results for the regional resource strategy with the proposed dual target as compared to a potential single target.

[12] Modeled portfolio costs do not include variable operations and maintenance costs for hydro or variable energy resources, non-power related utility costs, new transmission build costs, fixed operations and maintenance costs associated with the existing system and potentially other costs.

[13] More information on the adequacy check for the proposed regional resource strategy is included in Technical Appendix N – Scenario Modeling Results. As discussed in that technical appendix, the Council completed a full adequacy check for the proposed resource strategy assuming two different sets of hydro operations for fish and wildlife. The first is the operations as described in the Council's 2026 Columbia River Basin Fish and Wildlife Program and the second is the operations as described in the preliminary injunction issued by the federal district court in Oregon in March 2026. Technical Appendix N provides more details on the differences between these two operations, but the key differences relate to the spill levels in the fall and ramping of the system in spring and summer. For this analysis of the single target, the Council only conducted the adequacy check assuming the 2026 Fish and Wildlife Program.

[14] Technical Appendix M – Needs Assessment Results provides more details on the Council's multi-metric approach to assessing resource adequacy.

Table Q - 5: Adequacy Check Results

Metric	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
Proposed Strategy (dual target)	0.068	0.053	0.006	1.8	582	1,452
Shift to single target	0.136	0.118	0.016	3	1,237	3,505

The results show that shifting the conservation amount from the dual target approach to a single target approach, while keeping all other elements of the regional resource strategy the same, is not an adequate resource portfolio. Specifically, the single target strategy violates the Council's winter frequency and peak metrics, highlighted in the orange cells.

The Council's frequency metric avoids having adequacy events too frequently. It accounts for both seasonal limits (winter and summer) and an annual limit. A winter frequency metric of 0.1 loss of load events (LOLEV) means that the Council is planning for no more than 1 winter event in 10 years. A 0.118 LOLEV suggests slightly more frequent events than 1 in 10 years. The Council's peak metric (value at risk or VaR peak) is trying to protect against high-capacity shortfalls that are too large. Specifically, 39 out of 40 years, the Council wants to ensure that the maximum single-hour peak shortfalls do not exceed 1,200 MW. The 1,237 MW peak VaR found in the single target strategy test slightly violates that threshold.

While these violations are slight, it is important to keep in mind that the Council's approach to assessing resource adequacy is a binary approach. Under the standard used for the Ninth Power Plan, if one metric is violated, the portfolio is considered to be inadequate.

This finding demonstrates an important point regarding the proposed resource strategy in the draft Ninth Plan. The proposed strategy, including the dual target, while adequate, does not overly build towards the high loads. In other words, it is not a "gold plated" system overbuilding resources. If the strategy was in fact gold plated, a shift of 40 aMW of conservation from the west side of the region to the east would not likely be significant enough to make the strategy inadequate.

Should the Council develop a single target approach to conservation in its Final Power Plan, it will need to revisit the overall resource portfolio to ensure that there are sufficient resources to maintain adequacy. At this time, the Council has not determined what resources (and in what amounts) would be required for adequacy. Based on analysis conducted by staff in the development of draft Plan, the most likely approaches would be to increase either conservation, natural gas, or renewables recommendations by some amount.

Summary

This analysis focused on assessing the differences between including a dual versus a single conservation target in the regional strategy as currently defined in the draft Power Plan. The results show that, assuming the same level of conservation, moving from the proposed dual target to a single target would shift 40 aMW of cost-effective conservation by 2032 from the west side of the region (Oregon and Washington) to the east side of the region (Idaho and Montana).

This analysis also shows that from a regional perspective, that 40 aMW shift in conservation from west to east does not result in a significant difference in the overall portfolio costs. The shift in costs is not uniform across the region. Specifically, shifting cost-effective conservation from the west to the east results in a shift in investment from the west to the east.

Moving to a single target, assuming all else equal with the strategy, would result in a regional resource recommendation that is not adequate per the Council's adequacy criteria. To ensure that the Ninth Power Plan provides for an adequate, efficient, economical, and reliable power supply, the Council would need to consider other changes (specifically resource additions) to the overall resource strategy should the Council ultimately pursue a single target approach to conservation in the Final Power Plan.

Seeking Public Comment

This technical appendix was added to the draft Ninth Power Plan to provide more context around the inclusion of a dual target approach in the resource strategy for this draft plan, as well as some of the considerations from a regional planning perspective of a single target approach. The goal of providing additional context is to help the public when they are preparing comments on the Ninth Plan. The Council is interested in and seeking comments on all aspects of the draft Ninth Plan. Given the level of engagement in development of the draft Plan, the Council knows that the question around the shape of conservation target will be one area of significant discussion during the public comment period. The Council is interested in engaging in these discussions to become more informed on the issues, with a goal of ensuring the final power plan provides the most robust way for ensuring an adequate, efficient, economical, and reliable power supply.